

**Columbia Gas of Pennsylvania, Inc.
2012 General Rate Case
Docket No. R-2012-2321748
Standard Filing Requirements
Testimony - All
Volume 9 of 9**

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**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
MARK R. KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

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1 **1. Introduction**

2 Q. Please state your name and business address.

3 A. Mark R. Kempic, Southpointe Industrial Park, 121 Champion Way, Suite 100,
4 Canonsburg, PA 15317.

5 Q. By whom are you employed and in what capacity?

6 A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the
7 "Company") as the President.

8 Q. What are your responsibilities as the President?

9 A. I am the corporate officer responsible for the leadership of Columbia Gas of
10 Pennsylvania, Inc. and Columbia Gas of Maryland, Inc. and their various
11 departments, including Rates and Regulatory Policy, Governmental Affairs,
12 Communications and Community Relations.

13 Q. What is your educational and professional background?

14 A. I hold an Associate Engineering Degree in Solar Heating and Cooling Technology
15 from the Pennsylvania State University, a Bachelors of Science Degree in Computer
16 Science from the University of Pittsburgh and a Juris Doctor from the Capital
17 University School of Law in Columbus, Ohio. I held various positions within
18 Columbia and its parent company, NiSource Inc. ("NiSource") from 1979 through
19 1992 including emergency service dispatcher, engineering technician, information
20 systems analyst, gas supply and corporate planning analyst. From 1992 through
21 1994, I worked at a law firm where I represented the interests of industrial

1 customers in utility regulatory proceedings before the Public Utilities Commission
2 of Ohio and from 1994 until my return to Columbia/NiSource I worked as in-house
3 state regulatory counsel for an electric company. After rejoining Columbia in 1998
4 I initially served as an attorney, and was subsequently promoted to senior attorney
5 and then assistant general counsel. In October of 2009, I was named Director of
6 Rates and Regulatory Policy for Columbia. I assumed my current responsibilities
7 when I was named President in June 2012.

8 Q. Have you ever testified before a regulatory Commission?

9 A. Yes, I have testified before both the Pennsylvania Public Utility Commission
10 ("Commission") as well as the Maryland Public Service Commission. Most
11 recently, I have provided written testimony in Columbia's last two base rate cases
12 before the Commission at Docket Nos. R-2009-2149262 and R-2010-2215623.

13 Q. Please describe the scope of your testimony in this proceeding.

14 A. Through my testimony, I will provide the Commission with an overview of this base
15 rate filing, discuss the objectives that Columbia seeks to accomplish in this
16 proceeding, and discuss the Company's progress in its pipeline replacement efforts
17 and its enhanced focus on pipeline safety. I will also address Columbia's quality of
18 service in compliance with §523 of the Public Utility Code. Finally, I will introduce
19 Columbia's other witnesses who provide detailed testimony and supporting
20 documentation for all revenues, expenses and rate base elements included in the
21 fully forecasted rate year included in this base rate filing.

1 Q. Please describe briefly the corporate history of Columbia and its relationship with
2 its parent company, NiSource Inc. ("NiSource").

3 A. Columbia was incorporated on June 23, 1960 as a wholly-owned subsidiary of the
4 Columbia Gas System, Inc., under the Act of May 29, 1885, P.L. 29 of the
5 Commonwealth of Pennsylvania and commenced service as Columbia Gas of
6 Pennsylvania, Inc., on January 1, 1962, when it acquired the Pennsylvania retail
7 business of The Manufacturers Light and Heat Company, which was at that time
8 another wholly-owned subsidiary of The Columbia Gas System, Inc. In 1998, the
9 Columbia Gas System, Inc. became the Columbia Energy Group ("CEG"). In turn,
10 CEG merged with NiSource in 2000, at which time Columbia became one of ten
(10) natural gas distribution companies in the NiSource Corporate family.
12 Columbia is engaged in the business of furnishing natural gas service to
13 approximately 415,000 residential, commercial, and industrial customers pursuant
14 to certificates of public convenience and necessity issued by the Commission.
15 Columbia has its principal office in Canonsburg, Pennsylvania and provides natural
16 gas distribution service in portions of 26 counties in Pennsylvania, primarily in the
17 western half of the state, as well as parts of Northwest, Southern and Central
18 Pennsylvania.

19 NiSource, headquartered in Merrillville, Indiana, is an energy holding company
20 whose subsidiaries provide natural gas, electricity and other products and services
21 to approximately 3.8 million customers located within a corridor that runs from the

1 Gulf Coast through the Midwest to New England. NiSource is the successor to an
2 Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc.,
3 which changed its name to NiSource Inc. on April 14, 1999. In connection with the
4 acquisition of CEG on November 1, 2000, NiSource became a Delaware corporation
5 registered under the Public Utility Holding Company Act of 1935 (now known as
6 the Public Utility Holding Company Act of 2005). NiSource is also subject to the
7 jurisdiction of the Securities and Exchange Commission ("SEC") and is traded on
8 the New York Stock Exchange with the symbol "NI". The NiSource core operating
9 companies engage in natural gas transmission, storage and distribution, as well as
10 electric generation, transmission and distribution. NiSource's natural gas
11 distribution operations serve at retail over 3.3 million residential, commercial and
12 industrial customers with approximately 57,000 miles of pipeline in seven states
13 (Indiana, Kentucky, Maryland, Massachusetts, Ohio, Pennsylvania, and Virginia).
14 The NiSource gas distribution companies are: Bay State Gas Company dba
15 Columbia Gas of Massachusetts, Columbia Gas of Kentucky, Columbia Gas of
16 Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of
17 Virginia.

18 **2. Case Objectives**

19 Q. Please summarize Columbia's major objectives in this proceeding.

20 A. Columbia seeks Commission approval to increase its base rates to recover the
21 revenue requirement associated with Columbia's pipeline replacement program.

1 Second, Columbia seeks to recover the revenue requirement associated with its
2 increased focus on pipeline safety and other increasing operating costs. Third,
3 Columbia also seeks approval of a change to its residential rate design in order to
4 provide it with more certainty in the revenue received from residential customers.
5 Columbia believes that approval of these objectives is necessary for it to continue to
6 provide safe and reliable natural gas service at the lowest reasonable price to its
7 customers while providing the Company with a reasonable opportunity to recover
8 its costs and to earn a fair rate of return. Approval of these three objectives will
9 demonstrate to the investment community that the Commission supports the need
10 for more predictable earnings and the impact this has on utilities both of which will
11 encourage continued investment in gas utilities at reasonable costs of capital.
12 Finally, Columbia seeks approval of a Pilot "New Area Service" rider which will
13 encourage extension of distribution facilities into areas that are presently not
14 served by providing potential customers, for whom an extension is not currently
15 justified by the revenue to be produced, with the ability to pay an added charge to
16 their bill over a twenty year period instead of an up front deposit. My testimony
17 will outline, at a high level, the objectives of Columbia's filing. Details and
18 documentation supporting each of the objectives will be provided by Company
19 witnesses that I will introduce later in my testimony.

20 **2a. Proposed Rate Increase**

21 Q. Will you please explain Columbia's first objective?

1 A. Columbia first seeks recovery of, and an opportunity to earn a return on, the capital
2 investments made in its distribution system which are necessary to provide safe
3 and reliable natural gas distribution service to its customers. As a means of
4 introducing this issue, I would like to thank the Commission for recognizing the
5 importance of pipeline safety and distribution system infrastructure replacement
6 and I commend the Commission for efforts to work with Pennsylvania's General
7 Assembly in passage of Act 11 of 2012 ("Act 11"). I note that Columbia likewise
8 actively supported passage of Act 11 and Columbia plans to use all of the tools
9 offered by Act 11 in conjunction with Columbia's pipeline replacement effort. In
10 light of substantial capital investment Columbia made since its last rate case and
11 the fact that the legislation prohibits the filing of a Distribution System
12 Improvement Charge ("DSIC") until January 1, 2013, Columbia is filing this base
13 rate case using the fully projected future rate year contemplated by revisions to 66
14 Pa. C.S.A. § 315. That is not to say that Columbia will not use the DSIC provided for
15 by Act 11. Columbia plans to file, and use, the DSIC to recover those capital
16 investments that are not being recovered in the rates being charged to customers at
17 that time.

18 Q. What is Columbia's proposed rate increase in the case and what are some of the
19 primary drivers for the increase?

20 A. Columbia's last rate case increase went into effect on October 18, 2011. Now less
21 than one year after the new rates went into effect, Columbia suffers from a revenue

1 deficiency of \$77.3 million as detailed and supported in testimony of Company
2 witness Gore (Columbia Statement No. 4). Columbia notes that this revenue
3 deficiency is higher than in prior cases for two primary reasons: First, Columbia
4 has made, and continues to make, unprecedented and substantial capital
5 investments in its system and strives to serve as a model for bare steel replacement
6 programs in Pennsylvania. As detailed in Company witness Cote's testimony
7 (Columbia Statement No. 8), over the last three years Columbia has replaced more
8 than *four and one half times* as many miles of bare steel main as the next highest
9 local distribution company among its peers in Pennsylvania. In Columbia's last
10 base rate case, it stated that its capital budgets for age and condition replacement of
11 cast iron and bare steel ("CIBS") for 2011 and 2012 were \$86 million and \$96
12 million respectively. However, Columbia actually invested \$97 million in
13 replacement of CIBS pipe during 2011 and is on target to invest \$114 million in
14 replacement of CIBS in 2012. Columbia expects even higher levels of investments
15 in replacement of CIBS in 2013 and 2014 as detailed in Standard Data Request
16 GAS-ROR-14. These investment levels during 2011 and 2012 are among the largest
17 investments Columbia has ever made. I note that Columbia's ability to increase its
18 capital investment in 2012 and beyond is a result of Act 11's impact on reducing the
19 regulatory lag that was previously associated with utility investment in
20 Pennsylvania prior to the passage of Act 11.

1 Q. What is the other primary reason for the Company's large revenue increase in this
2 case?

3 A. The revenue deficiency in this case is also higher than in prior cases because
4 Columbia is using the fully forecasted rate year authorized by Act 11. Under Act 11,
5 rates may be determined by a "fully projected future test year, which shall be the 12
6 month period beginning with the first month that the new rates will be placed in
7 effect". In other words, this rate case includes the revenue requirement associated
8 with the capital invested prior to the rate effective date as well as the capital
9 invested during the fully forecasted rate year, whereas prior rate cases included
10 only the capital invested prior to the rate effective date. After this rate case
11 "adjusts" the time period and places Columbia on a forward-looking schedule,
12 Columbia anticipates that requested increases in future rate cases will return to a
13 more moderate level. In addition, once utilities are able to file DSIC after January
14 1, 2013 and recover a portion of their revenue requirement through the DSIC, the
15 net effect of future rate increase requests will moderate.

16 Q. Is Columbia concerned about continued pipeline contractor availability in light of
17 the fact that Act 11 encourages Pennsylvania's other gas and electric utilities to
18 increase their investments in replacing utility infrastructure?

19 A. No. Columbia anticipated that contractor availability might become a concern as
20 more and more gas utilities seek to replace their aging infrastructures and
21 Columbia has taken efforts to ensure that it will continue to have pipeline

1 contractors available. Specifically, last fall Columbia initiated a contracting event
2 where Columbia discussed its long term program with those incumbent contractors
3 who were the successful bidders in the last two competitive bidding processes and
4 that have met or exceeded Columbia's and its customers' expectations. Columbia
5 successfully reached agreements with those contractors. Highlights of the new
6 contracts are shown below.

- 7 • New contracts established as of July 1, 2012.
- 8 • Extended the term until December 31, 2015.
- 9 • Alignment of the contract year with the calendar year beginning in
10 2013.
- 11 • Broadened geographic coverage enabling contractors to work across
12 operating center boundaries.
- 13 • Expanded the contract scope to include projects involving
14 polyethylene pipe up to \$5,000,000 in contract spend.
- 15 • Added mechanisms for quarterly adjustments to baseline indexed
16 values for gasoline and asphalt plus accounted for unexpected costs
17 to complete contractual requirements.
- 18 • Included an annual contract adjustment that is tied to a national
19 Laborer's contract for the Mid-Atlantic Region, Local 1058, Allegheny
20 Zone 2, Pennsylvania Contract.

- Aligned the responsibility for hard surface restoration to the construction contractor that generated the work.

Each one of these changes was designed to enhance Columbia's ability to continue to execute efficiently on its large scale capital program by providing certainty, clarity and flexibility in the relationship between Columbia and its pipeline contractors. The new contracts establish a long term, cost effective means of replacing Columbia's cast iron and bare steel pipe. Columbia views its proactive approach in both identifying the potential for a scarcity of contractors as well as its execution of the contracting event and the negotiation of multi-year contracts as evidence of the effectiveness of Columbia's management team.

2b. Pipeline Safety Enhancements

Q. What is Columbia's second objective in this case?

A. In addition to the capital costs associated with Columbia's accelerated pipeline replacement effort, Columbia is incurring operating and maintenance costs associated with enhancing pipeline safety on its system, and Columbia seeks recovery of those increased operations and maintenance costs directly associated with increased pipeline safety activities which are necessary to meet new pipeline safety rules and regulatory advisories. As described in detail in Company Witness Cote's testimony, Columbia is undertaking new efforts which will further enhance the safety and reliability of Columbia's distribution system. These efforts include accelerating the repair rate of open class 2 leaks; insourcing distribution pipeline

1 locating work that was previously outsourced to third party contractors; adding
2 three damage prevention coordinators to further reduce the number of third party
3 damages to Columbia's facilities; running cameras through sewer lines to identify
4 any cross-bore conflicts; deploying GPS technology to identify the location of all
5 new facilities; hiring three mapping technicians to support the GPS effort and
6 ramping up Columbia's damage prevention educational efforts and contractor
7 outreach. Collectively, all of these efforts will cause an annual increase in O&M
8 costs of approximately \$9.25 million per year. All of these activities are directly
9 designed to further improve the safety and reliability of the natural gas distribution
10 service that Columbia provides to the public. Company witness Cote and Company
11 witness Kitchell (Columbia Statement No. 7) support the need for these expenses in
12 detail and Company Witness Gore provides detail of the costs associated with these
13 efforts.

14 **2c. Modernize Residential Rate Structure**

15 Q. What is Columbia's third objective in this rate case?

16 A. Columbia is again proposing to modernize its rate structure. In Columbia's last
17 rate case, Columbia sought the Commission's approval of a "levelized distribution
18 charge" for residential customers. Ultimately, the levelized distribution charge was
19 not approved by the Commission. Instead, the Commission approved a rate
20 structure proposed by the Bureau of Investigation and Enforcement ("BI&E")
21 which consisted of an \$18.73 customer charge and a usage based rate of \$2.68 per

1 Mcf that applied to all consumption in excess of 2 Mcf¹ in any given month. The
2 Commission stated in its Order that it did not consider the rate design adopted to
3 be “precedential,” and encouraged the future submission of alternative rate
4 mechanisms to balance the needs of customers and utilities.

5 Q. Did the rate design that was approved in your last rate case address Columbia’s
6 concern of providing more certainty?

7 A. No, while the rate design approved by the Commission may provide a bit more
8 revenue certainty during the summer, non-heating months, it provides no further
9 revenue certainty in the winter months. The winter months are when Columbia
10 experiences the most uncertainty due to temperatures that significantly depart
11 from the normal temperatures Columbia uses to establish its base rates and
12 conservation efforts. The revenue uncertainty deals with the last volumes of gas
13 used, not the first few Mcf. Stated another way, nearly all of Columbia’s customers
14 already use more than 2 Mcf each month in the winter so including a 2 Mcf
15 allowance in the fixed charge did not improve revenue certainty - it simply moved
16 the charge the customer paid anyway from the usage based charge to the fixed
17 charge. As it turns out, after Columbia implemented the rates approved by the
18 Commission in the last rate case in October 2011, Pennsylvania experienced one of
19 the warmest winters in history. As a result, Columbia did not earn the revenue

¹ As part of the partial settlement in the last case, Columbia has implemented therm billing, and thus the usage allowance is 21 therms and the usage based distribution rate over the allowance is \$0.267 per therm.

1 anticipated in the last rate case and the modified residential rate design provided
2 no insulation from the warm weather.

3 Q. Why is revenue certainty from the residential class important?

4 A. Over 70% of Columbia's revenues come from the residential class of customers.
5 Columbia's annual non-gas revenue from residential customers during the historic
6 test year is approximately \$152 Million. Under the current residential rate design,
7 approximately 56% of Columbia's revenue requirement from the residential class
8 may be viewed as generated on a fixed basis, including the 2 Mcf allowance that, as
9 noted above, did not really increase revenue certainty in the winter. That means
10 approximately \$67 million of Columbia's annual residential revenue requirement is
11 not generated on a fixed basis, but is instead dependent on factors that are not
12 under Columbia's control such as the weather and customer conservation efforts.
13 That \$67 million revenue requirement is comparable to the revenue requirement
14 necessary to support a capital program of over \$450 million dollars. When the
15 large scale annual capital investment being made by Columbia is considered in
16 conjunction with the fact that 44% of Columbia's revenue is subject to recovery
17 based upon customer usage, it makes Columbia a less attractive investment when

1 compared to other utilities that have more certainty in their revenue recovery.²
2 Obviously from an investor's perspective, when Columbia is investing in excess of
3 \$100 million every year, it is less than an ideal situation for Columbia to be given
4 the opportunity to recover \$67 million in residential revenues only during cold
5 weather and only if customers do not adopt further conservation efforts to reduce
6 usage.

7 Q. While the current rate design does not provide Columbia with revenue protection
8 from warmer than normal weather, does the rate design provide any benefit?

9 A. Even though the current rate design does not provide the necessary certainty of
10 residential revenues, it served as an important test for customer acceptance in that
11 it proved that residential customers would accept increased fixed charges for their
12 distribution service. In fact, Columbia has only received only 4 informal
13 complaints and one formal complaint dealing with the \$18.73 residential fixed
14 charge. With approximately 375,000 residential customers, that means less than
15 0.0013% of customers objected to the level of the customer charge.

² As Company witness Moul testifies, all of the gas utilities in the peer group but one have some form of revenue decoupling or protection against the weather. Indeed, the same is true even within NiSource. All of the other gas distribution companies within the NiSource Gas Distribution segment of NiSource have recently made dramatic improvements in the amount of revenue recovered from residential customers on a fixed basis. Columbia Gas of Ohio, Inc, completely recovers its full residential revenue requirement through a fixed flat "Levelized Distribution Charge"; Columbia Gas of Virginia, Inc., and Columbia Gas of Massachusetts both have revenue normalization adjustment mechanisms; Columbia Gas of Maryland, Inc. has had a weather normalization adjustment for its residential customers for years; and the Kentucky Public Service Commission has authorized Columbia Gas of Kentucky, Inc. to gain more certainty in its residential revenue by applying the entire revenue increase in Columbia's last two base rate cases to the customer charge.

1 Q. Why does Columbia's desire to adopt a new rate structure for residential
2 customers?

3 A. While many other states have approved alternative rate designs to decouple
4 revenues from usage, Pennsylvania has not. Therefore, Columbia and other
5 Pennsylvania gas utilities are at a distinct disadvantage when compared to utilities
6 in other states. An investor would demand a substantial premium to be willing to
7 invest in a Pennsylvania utility that recovers its costs through a mechanism that is
8 largely dependent on the weather and customer usage, when they can invest in a
9 utility in another state that will permit revenue recovery through rate structures
10 that are not dependent on the whim of the weather and customer usage patterns.
11 When coupled with press coverage about climate change and the warming earth,
12 investors are not incentivized to invest in a utility that recovers its costs in the
13 current Pennsylvania regulatory paradigm.

14 **2c(1). Modern Rate Design in Other States**

15 Q. Do you have any examples of what other states have done?

16 A. Columbia's affiliated company, Columbia Gas of Ohio, Inc. ("COH") received
17 approval from the Public Utilities Commission of Ohio of a straight fixed/variable
18 rate design which gives investors more certainty that the utility will recover its
19 revenue requirement since COH no longer needs to count on cold weather for its
20 revenues. (Order dated Dec. 3, 2008 at Case Nos. 08-0072-GA-AIR, 08-0073-GA-
21 ALT, 08-0074-GA-AAM and 08-0075-GA-AAM). It is important to note that the

1 Ohio Supreme Court recently upheld the use of a “straight fixed variable” rate
2 design for gas utilities in Ohio.³ The Court found that the Ohio Commission had
3 the discretion to approve such a rate design, and that the rate design would, on
4 average, benefit low income customers since low-income customers are, on
5 average, high use customers.⁴ The court also upheld the Commission’s finding that
6 the SFV rate design remedies inequities in the prior volumetric rate structure,
7 under which high-use customers overpay their own fixed costs and subsidize low-
8 use customers.⁵ While I recognize that the Ohio statutory and regulatory structure
9 differs from that of Pennsylvania, this is evidence of the fact that other states have
10 adopted innovative rate mechanisms and, from a utility investor-relations
11 perspective, this puts Pennsylvania gas utilities at a disadvantage. That
12 disadvantage can be detrimental to Pennsylvania utility customers.

13
14 Another example is in Massachusetts, where the Department of Public Utilities
15 (“the Department”) approved decoupling for Columbia’s affiliate Columbia Gas of
16 Massachusetts (“CMA”) (Bay State Gas Company d/b/a Columbia Gas of
17 Massachusetts). (Order dated Oct. 30, 2009 at Docket No. D.P.U. 09-30). The
18 Department approved CMA’s revenue decoupling mechanism structured as a
19 “revenue per customer” approach for all customer classes. Under this approach,

³ *Ohio Consumers’ Council v. Pub. Util. Comm.*, Slip Opinion No. 2010-Ohio-6239 (Dec. 23, 2010).

⁴ *Id.*

⁵ *Id.*

1 CMA adjusts its rates semi-annually for all firm gas sales and all firm
2 transportation service in order to reconcile actual base revenue recoveries with
3 Benchmark base revenues. Benchmark base revenues are calculated for each
4 customer class group for the peak and off-peak seasons, reflective of CMA's most
5 recent base rate proceeding. This mechanism serves to eliminate the link between
6 customer volumes and CMA's earnings, thereby aligning the interests of CMA and
7 its customers with respect to lowering customer usage. This rate design was used
8 as the basis for Columbia's preferred option in this case.

9
10 Yet another example is Virginia, in which the State Corporation Commission
11 ("SCC") approved decoupling for Columbia Gas of Virginia, Inc. ("CVA") by an
12 Order dated October 28, 2009 at Case No. PUE-2009-0051. Under the terms of
13 that Order, CVA has instituted a Revenue Normalization Adjustment ("RNA")
14 designed to reconcile weather-normalized non-gas-distribution revenues per
15 customer to allowed distribution revenues per customer. The RNA is revenue
16 neutral and does not shift annualized distribution revenue between customer
17 classes. Instead, it serves to mitigate the impact of decreasing sales on CVA's ability
18 to recover its costs. In addition, on December 17, 2010 the SCC granted CVA a rate
19 increase in which it increased fixed customer charges for all classes of customers
20 and also approved a weather normalization adjustment, both of which help
21 mitigate the impact of weather on CVA's revenues and thereby make CVA a more

1 attractive option for investors. The RNA applies to residential customers and
2 commercial small general service customers, but will not apply to industrial small
3 general service customers. Case No. PUE-2010-000017 (December 17, 2010).

4 Q. Have other state regulatory agencies approved similar non-traditional ratemaking
5 designs?

6 A. Yes. These are just three of many examples of what other states have done recently
7 to address incentives for investment in infrastructure replacement programs and
8 energy conservation programs. As illustrated by the map in Figure 1 below,
9 according to the American Gas Association, as of March 2012, thirty-three states
10 have now approved decoupling, flat fees or rate stabilization tariffs for utilities.
11 Another two states have similar mechanisms pending approval. As of March, 2012,
12 45 million utility customers across the United States are receiving bills with more
13 modern rate designs than Pennsylvania utility customers enjoy.

States with Non-Volumetric Rate Designs
(Decoupling, Flat Monthly Fee, Rate Stabilization)
33 Approved, 2 Pending As of March 2012



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1 A. Credit reporting agencies and investors notice these actions. They understand how
2 important rate structures are to a utility's financial health, and they understand
3 how the lack of opportunities for more certain recovery can discourage investors.
4 Without a rate structure that provides more certainty, Columbia will be required to
5 file more frequent base rate cases in Pennsylvania to reflect the effects of
6 continuing conservation. The investment community is well aware of this hurdle,
7 as evidenced by the comments provided to the Commission by Mr. Richard
8 Cortright, Managing Director in the Utilities & Infrastructure Practice of Standard
9 & Poor's Ratings Services during the Commission's November 19, 2009 Technical
10 Conference concerning the ARRA. At that technical conference he stated "...we as a
11 rating agency will be closely focused on the various recovery mechanisms that
12 regulators establish to enable utilities to recover their costs --- in particular those
13 costs over which they have little to no control --- on a timely basis."⁶ Mr. Cortright
14 continued: "To the extent that a commission has established recovery mechanisms
15 such as the various trackers noted on this slide, as well as decoupling mechanisms,
16 we would view a commission as being supportive of and attentive to the
17 creditworthiness of a utility."⁷

18 Q. Is Columbia again recommending that the Commission adopt the Levelized
19 Distribution Charge as a rate design for residential customers?

⁶ *American Recovery and Reinvestment Act Technical Conference ("ARRA Technical Conference")*, PUC Docket No. I-2009-2099881 (Nov. 19, 2009) (Standard & Poors Comments at 3; Transcript of Record at 99).

⁷ *Id.* at 100.

1 A. While Columbia believes the Levelized Distribution Charge is a superior rate design
2 because of its simplicity and its direct relation to the manner in which Columbia
3 incurs its costs to provide distribution service, Columbia recognizes that the parties
4 and the Commission disagree. Therefore, in accordance with the Commission's
5 recommendation in Columbia's last rate case, Columbia is providing two rate
6 design options in addition to the Levelized Distribution Charge for residential
7 customers, all of which are intended to provide more certainty in the recovery of
8 Columbia's fixed investments in replacement pipe.

9 **2c(2). Modern Rate Design Options**

10 Q. Please describe each of the three options.

11 A. Columbia's first rate design proposal incorporates a "Revenue Normalization
12 Adjustment" rate design which would essentially determine the revenue the
13 residential customer class is responsible for, and adjust to that level of revenue
14 regardless of the gas usage. Columbia's second option is a Weather Normalization
15 Adjustment, which contemplates adjusting a residential customer's monthly
16 revenue based on the actual temperature experienced during the month.
17 Columbia's third option is the levelized distribution charge. While each of the three
18 options would be acceptable to Columbia, Columbia recommends adoption of the
19 first "Revenue Normalization Adjustment" option because it believes it best
20 addresses concerns raised by parties in prior proceedings of attracting revenue
21 certainty while still maintaining usage based charges that reflect individual

1 customer consumption patterns. Company witness Strauss (Columbia Statement
2 No. 15) explains the bill impacts of each option and explains the first two options in
3 great detail and since the levelized distribution charge is the same concept that I
4 had described in Columbia's last base rate case, I will describe it.

5 Q. Would you please describe the levelized distribution charge option for the
6 residential customer class?

7 A. A levelized distribution charge would allow Columbia to recover its fixed costs of
8 providing gas utility service in a simplified, single flat charge and thereby provide
9 more certainty that Columbia will ultimately recover its investment in replacing all
10 of the CIBS in its distribution system regardless of uncontrollable variables such as
11 the temperature, customer consumption patterns, and declining use. Under

12 Columbia's current rate structure, much of Columbia's large scale capital
13 investment in replacing CIBS is recovered through usage based charges even
14 though the quantity of gas distributed has no bearing on the cost of replacing CIBS.

15 Stated another way, Columbia's revenues are presently decoupled from the costs it
16 incurs to provide service. This rate design illogically subjects the recovery of
17 Columbia's fixed costs to the vagaries of weather, usage patterns or economic
18 conditions. Once a pipe is installed, it does not matter whether that pipe carries
19 one cubic foot of gas or one hundred cubic feet of gas—the cost of installing that
20 pipe does not change by the amount of gas going through it. Because of this rate
21 structure, when customers consume less gas due to warmer than expected weather

1 or due to the impact of energy efficiency programs, Columbia's revenues drop—but
2 its costs do not. By the same token, when weather is colder than normal,
3 Columbia's customers are essentially required to overpay for Columbia's fixed
4 costs.

5 Q. How does the current rate structure recover the company's costs of providing gas
6 distribution service?

7 A. Columbia's residential customer's bill now contains three basic parts: 1) the fixed
8 charge; 2) the usage-based distribution charges for consumption over 21 therms;
9 and 3) the usage based gas commodity charges. Columbia recovers its costs and
10 derives its revenue from both the fixed charge and the usage based distribution
11 charge. The usage based commodity charge recovers the cost of the gas itself and
12 Columbia does not earn a profit on the commodity component. This general rate
13 structure has been in place for quite a long time, but it is still misunderstood by
14 customers, as evidenced by the purchased gas cost complaints received in base rate
15 cases and the base rate issues raised by customer complainants in purchased gas
16 cost proceedings.

17 Q. Why do you believe it confuses customers?

18 A. This usage-based distribution charge rate structure is confusing because it bears no
19 relationship to the manner in which a utility incurs costs to provide customers with
20 gas distribution service. The usage-based distribution charge suggests to customers
21 that the utility's costs to provide distribution service increase as the customer uses

1 more gas, but that is simply not true. With the exception of the cost for gas odorant
2 which increases as consumers use more gas, none of the Company's distribution-
3 related costs increase as customers consume more gas. While this has always been
4 the case, the inappropriate usage-based distribution charge has misled customers
5 over the years so that customers now believe a gas utility's costs increase as the
6 customers use more gas.

7 Q. Do you believe most customers care about how a gas utility recovers its costs?

8 A. Customers may not care about how a utility recovers its costs, but customers want
9 bills that are easy to understand and they want to be treated fairly. Moving to a
10 structure in which virtually all of the utility's costs are recovered through a flat fee
11 will simplify the bill by splitting it into two primary components: one to recover the

12 company's costs of distribution service and the other to recover the cost of the gas
13 consumed. Under this rate design, Rider USP will continue to be applied on a
14 usage basis because majority of the costs recovered by Rider USP relate to gas
15 commodity costs. With a fixed charge for distribution service, customers will be
16 given a correct price signal regarding the company's cost of providing distribution
17 service and customers will clearly see how much the gas commodity costs them
18 each month. Simplifying the bill by splitting it into the "pipes" and the "gas"
19 components will therefore enhance customers' ability to understand the value of
20 Choice.

21 Q. How would a levelized rate structure treat customers more fairly?

1 A. Since the current usage-based distribution rate bears no relationship to the manner
2 in which the Company incurs its costs, customers are at risk for underpaying or
3 overpaying their fair share of the cost of service. To make matters worse,
4 customers are placed at risk of overpaying or underpaying for their distribution
5 service based on things that have no bearing on the cost of distribution service like
6 the age of their appliances, or based on things beyond their control like the
7 temperature. Moving to a Levelized Distribution Charge removes this inequity.

8 Q. Is there any support for moving to a Levelized Distribution Charge?

9 A. As evidenced by the comments of other Pennsylvania gas utilities at the
10 Commission's November 19, 2009 technical conference, the Pennsylvania gas
11 industry is unified on the position that utilities should recover more of their fixed
12 costs through a fixed customer charge.⁸ In addition, Mr. Cortright of Standard &
13 Poor's provided comments to the Commission about the investment community's
14 view of decoupling revenues from volumetric rates.⁹ Mr. Cortright's comments
15 indicated that Standard & Poor's views decoupling¹⁰ as positive from a credit
16 perspective since it provides the opportunity for a utility to earn a pre-determined
17 level of distribution revenue regardless of the actual volume sold.¹¹ This enables
18 utilities to project cash flows more accurately and reduce much of the volatility

⁸ Transcript of Record at 33-88, *ARRA Technical Conference* (Nov. 19, 2009).

⁹ *Id.* at 100-01.

¹⁰ A Levelized Distribution Charge is a form of revenue decoupling

¹¹ *Id.* at 100.

1 from changes due to influences such as the weather or the economy that occur
2 under traditional rate mechanisms.¹²

3 **2d. Revenue Requirement**

4 Q. How did Columbia determine the revenue requirement for this case?

5 A. As described in the testimony of Company witness Gore, Columbia reviewed its
6 costs to serve its customers using a fully forecasted rate year ending June 30, 2014,
7 pro forma and adjusted for known and measurable changes. Columbia then
8 compared the costs determined for the fully forecasted rate year to the revenues at
9 present rates calculated for the fully forecasted rate year. This analysis produced a
10 revenue deficiency, from which Columbia calculated the corresponding revenue
11 requirements that Columbia will require to make up this deficiency with a fair rate
12 of return on the investments devoted to serving the public.

13 Q. Why is the proposed rate increase necessary to eliminate the revenue deficiency?

14 A. Columbia's current rates do not provide the opportunity for the Company to
15 recover its costs to serve its customers, including a fair rate of return on the capital
16 invested to provide distribution service to the public. The proposed rates have been
17 developed to eliminate this deficiency and Company witness Moul will support
18 Columbia's rate of return in his testimony.

19 Q. Without the increase requested in this case, what will Columbia's rate of return be?

¹² *Id.*

1 A. Without the increase requested, Columbia's rate of return will be 7.476% during the
2 Historic Test Year and it will drop to 4.114% in the Fully Forecasted Rate Year.

3 Q. What overall return and return on equity does Columbia propose in this case?

4 A. Columbia proposes an overall rate of return of 8.52%. Columbia witness Moul's
5 testimony demonstrates that Columbia should be granted an opportunity to earn
6 an 11.25% rate of return on common equity.

7 **3. Management Performance**

8 **3a. Customer Satisfaction**

9 Q. Please provide evidence concerning the performance of Columbia's management
10 and the quality of service that Columbia is providing to its customers.

11 A. Columbia's management consistently performs above industry averages and
12 provides a superior level of customer service as measured by numerous industry
13 and Commission metrics. Columbia uses two outside contractors to gauge
14 customer satisfaction and the quality of the service that Columbia provides to its
15 customers. Those contractors are Thoroughbred Research and Metrix/Matrix.
16 Metrix/Matrix is an independent firm that also performs the Commission's
17 "Customer Transactional Survey", which is part of the Quality of Service
18 Benchmarking Performance Report. Additionally, Columbia's call center performs
19 its own internal survey to determine the level of service it is providing to its
20 customers.

1 Results of all three surveys over the past several years indicate that Columbia's level
2 of service within its call center has remained consistently high. In the measures
3 gauging the Call Center Representatives (CSRs) Courtesy and Knowledge, our
4 customers continue to rate our CSRs with a 90%+ satisfaction grade. In addition,
5 Columbia's Field Service Representatives received high marks (95%+) from our
6 customers in the measures of courtesy and knowledge, as recorded in the
7 Commission's 2011 Quality of Service Benchmarking Report.

8
9 Figure 2 below depicts the survey results of the Thoroughbred Research Survey for
10 the past five years. As is evident from these results, Columbia's call center has
11 maintained a high level of customer satisfaction with its customers, a 94% average.

12 A real key to the effectiveness of Columbia's call center has been a marked
13 improvement in the measure of first call resolution with the customer. "First call
14 resolution" is a statistic that reflects the success of the call center's ability to resolve
15 a customer concern at the first contact with the Company.

Figure 2

Columbia Gas of Pennsylvania	2007	2008	2009	2010	2011	2012
						3-Month average March
Thoroughbred CSR Attributes	12-month	12-month	12-month	12-month	12-month	2012
• Being courteous and professional	0.94	0.93	0.94	0.96	0.96	0.98
• Treating as respected customer	0.94	0.93	0.94	0.96	0.94	0.97
• Showing concern for situation	0.91	0.89	0.91	0.93	0.92	0.94
• Displaying knowledge in job	0.93	0.93	0.93	0.95	0.94	0.96
• Adequately answering questions	0.93	0.92	0.93	0.95	0.94	0.97
• Understanding purpose for call	0.93	0.91	0.93	0.94	0.95	0.98
• Having authority to make decisions	0.89	0.87	0.89	0.92	0.92	0.94
• Working quickly and efficiently	0.91	0.89	0.92	0.93	0.92	0.96
**Source document = Thoroughbred Survey website/Columbia Gas of Pennsylvania/Monthly Flash Report/12-month and 3-month average						

Figure 3 below reflects first call resolution statistics for the past three years, including year-to-date information for 2012. Since 2009, when Columbia first began tracking this statistic, Columbia's first call resolution performance has improved from 66% to 81% in 2011. This statistic supports data presented by Metrix/Matrix in the Commission's Quality of Service Benchmarking Report that indicates that only 11% of Columbia customers surveyed requested a follow up visit by our service department. Columbia's performance was the best in the Pennsylvania gas industry during 2011. The industry average was 16%.

Figure 3

Columbia Gas of Pennsylvania, Inc. Performance Statistics											
2009			2010			2011			2012		
CPA	Cust. Sat.	1st Call Res.	Cust. Sat.	1st Call Res.	Ease of Conducting Business	Cust. Sat.	1st Call Res.	Ease of Conducting Business	Cust. Sat.	1st Call Res.	Ease of Conducting Business
Jan	91%	74%	95%	82%	85%	94%	74%	96%	100%	88%	98%
Feb	89%	69%	94%	71%	97%	96%	76%	86%	97%	79%	82%
Mar	95%	59%	96%	61%	94%	93%	90%	94%	96%	88%	97%
Apr	95%	53%	95%	74%	97%	96%	94%	97%			
May	88%	67%	98%	69%	95%	97%	86%	94%			
Jun	97%	56%	91%	65%	91%	95%	75%	86%			
Jul	94%	72%	94%	67%	79%	93%	72%	87%			
Aug	88%	73%	97%	68%	92%	93%	78%	72%			
Sep	97%	64%	97%	77%	87%	90%	84%	88%			
Oct	93%	66%	95%	73%	90%	93%	85%	80%			
Nov	100%	68%	95%	71%	92%	93%	69%	96%			
Dec	94%	72%	89%	72%	97%	97%	78%	91%			
YTD	94%	66%	94%	71%	91%	94%	80%	88%	97%	84%	90%
Target	91%	69%	91%	69%	86%	91%	69%	87%	92%	70%	88%
12 Month Avg	94%	66%	94%	71%	91%	94%	80%	88%	94%	81%	88%

Columbia did not begin tracking the "Ease of Conducting Business" section of the survey until 2010, so there is not any data available for 2009. The data shown is a monthly snapshot of the metrics tracked by the Customer Contact Center portion of the organization.

A significant measure of quality Call Center performance used in the industry is the busy-out rate which measures the percent of calls that receive a busy signal and ultimately do not reach the company because the phone lines were at capacity (this excludes emergency calls). We are pleased to report that Columbia's busy-out rate for the past 8 years has remained at 0%. Additionally, Columbia had the lowest call abandonment rate in Pennsylvania's gas industry during 2011. During that time, Columbia's call abandonment rate was 2% as reported in the Commission's 2011 Quality of Service Benchmarking Report.

1 This report also shows the success of Columbia's customer billing function. In
2 2011, Columbia did not have any deferred residential or small commercial billings.
3 This indicates that Columbia is both investigating and resolving its billing problems
4 as well as rendering its bills in a timely manner. Columbia was the *only* gas utility
5 in Pennsylvania to achieve this level of performance in 2011.

6
7 Recently, the Commission issued its 2011 Annual Activity Report ("UCARE"),
8 which details complaint activity for each of the major gas, electric, water and
9 telephone utilities in Pennsylvania. Based on the results of this report, Columbia
10 continues to perform better than the industry average in every category (consumer
11 complaints, payment arrangement requests, and compliance). Columbia's
12 Consumer Complaint rate per 1,000 residential customers was .61 in 2011 and its
13 Payment Arrangement Request rate per 1,000 residential customers was 2.24.
14 Again, these rates are significantly better than the industry average.

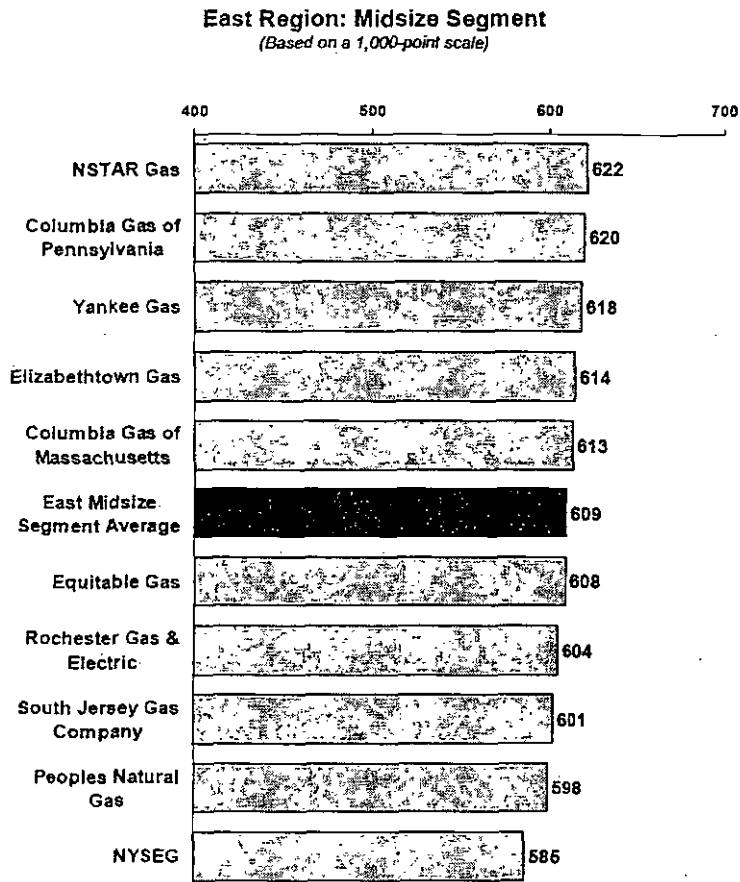
15
16 In order to maintain and even improve its customer satisfaction, Columbia
17 continues to make enhancements to its web functionality to provide its customers
18 with additional online reporting options and information and services. Recently,
19 Columbia implemented a mobile web site, which will give customers the ability to
20 access it from their hand held mobile device. The key features this site will offer
21 are, pay by phone, report a gas leak/emergency, find a payment location, and

1 “contact us”. Columbia also significantly expanded its website functionality to
2 provide its customers with additional and enhanced online options and information
3 and services. Columbia offers budget plan information, one-time payments by
4 check, enrollment or cancellation for reoccurring payments, the ability to enter
5 meter readings and update personal information and e-bill through its website.
6 Under certain conditions, customers can also use the website to turn-on,
7 disconnect or transfer service.

8
9 As shown in Figure 4 below, in another customer satisfaction measure, according to
10 the most recent 2011 J.D. Power Residential Customer Satisfaction Survey,
11 Columbia once again ranked in the top quartile among the other mid-size local gas
12 utilities in the east region. Columbia's overall customer satisfaction rating was 11
13 points higher than the east midsize segment average.

Figure 4

J.D. Power and AssociatesSM
2011 Gas Utility Residential Customer Satisfaction Study



Source: J.D. Power and Associates 2011 Gas Utility Residential Customer Satisfaction StudySM

Charts and graphs extracted from this press release must be accompanied by a statement identifying J.D. Power and Associates as the publisher and the J.D. Power and Associates 2011 Gas Utility Residential Customer Satisfaction StudySM as the source. Rankings are based on numerical scores, and not necessarily on statistical significance. No advertising or other promotional use can be made of the information in this release or J.D. Power and Associates survey results without the express prior written consent of J.D. Power and Associates.

In addition to this superior past performance, Columbia's management continually explores ways of further enhancing the customer's experience. For instance, in 2010, Columbia implemented a program for new customers wishing to become

1 Columbia Gas customers. The program, called "10 Day Tap Pledge", was developed
2 to expedite the new business process. Columbia's New Business Team's goal is to
3 install the tap and the customer's service line within 10 business days, once the
4 builder meets Columbia's site readiness requirements, and we receive approval of
5 all necessary state permits. Columbia launched this program to enhance the quality
6 of service it provides to the public and believes this program will improve customer
7 satisfaction. In 2011, Columbia was able to meet the "10 Day Tap Pledge" to its
8 customers 95% of the time.

9 **3b. Low Income and Customer Programs**

10 Q. Please describe Columbia's efforts in the area of low income programs.

11 A. Columbia maintains its focus on providing its low income customers with
12 appropriate tools, resources and programs. Columbia has a broad menu of options
13 for low income, payment-troubled customers. In addition to Low Income Home
14 Energy Assistance Plan ("LIHEAP") referrals, Columbia encourages customers to
15 take advantage of its Customer Assistance Program ("CAP"), Customer Assistance,
16 Referral & Evaluation Services ("CARES"), Dollar Energy Fund, WarmWise-Low
17 Income Usage Reduction Program, Crisis - Emergency Energy Assistance,
18 Emergency Repair Program, and the Budget Payment Plan. Our goal is to notify
19 and educate customers and urge them to participate in available energy assistance
20 programs. Columbia's communication efforts include participating in community

1 outreach events, a formal advertising campaign, press releases and bill inserts to
2 customers.

3 In addition, Columbia's Call Center staffing includes a Universal Services Call
4 Group, which is comprised of individuals who are specially trained to assist low
5 income, payment-troubled customers. This call group is informed of the most up
6 to-date program guidelines and application processes. They strive to link our
7 customers to the most appropriate resources to address their particular concerns as
8 efficiently as possible.

9 Q. Does Columbia offer other programs to its customers besides the low income
10 programs explained above?

11 A. Yes, Columbia offers an energy efficiency program called "WarmWise Audits &
12 Rebates" ("WarmWise-A&R") which was formerly called the "Income Qualified
13 Usage Reduction Program" ("IQEEP"). Customers who are not eligible for
14 Columbia low income programs such its Low Income Usage Reduction Program
15 ("LIURP") may be eligible for WarmWise-A&R.

16 Q. Can you explain the scope of the program?

17 A, Yes. The WarmWise-A&R offers energy efficiency benefits to customers who are
18 slightly over the income qualification for Columbia's WarmWise LIURP.
19 Specifically WarmWise-A&R offers a free Building Performance Institute audit
20 ("BPI") to customers as well as upfront rebates towards the installation of audit

1 recommended measures to customers who are between 151% and 250% of the
2 Federal Poverty Guideline.

3 Q. Does Columbia request any modifications to the WarmWise-A&R program?

4 A. Columbia does not request permission for any particular program modification at
5 this time; however, Columbia requests permission to make changes and
6 enhancements to the WarmWise-A&R program design and implementation
7 without seeking Commission approval for each individual change provided that the
8 program costs do not exceed its currently approved annual funding level of
9 \$750,000. In other words, Columbia would like the approval to manage the
10 program within the authorized budget without continually seeking approval of each
11 individual change.

12 Q. Please provide some examples of changes that Columbia would possibly make to
13 the program.

14 A. Columbia can provide three examples of potential modifications to its WarmWise-
15 A&R program. Columbia would like to make a "Safety Rebate" available to certain
16 customers participating in WarmWise-A&R. The WarmWise-A&R program offers
17 diagnostic testing of appliances during the BPI audit. This diagnostic testing often
18 detects gas leaks and gas combustion emergencies that may have otherwise gone
19 undetected if not for the BPI audit. Unlike Columbia's low income weatherization
20 program, WarmWise LIURP, where such safety repairs are paid for by the
21 Company, the customers who participate in the WarmWise-A&R program are held

1 responsible for the repairs of their appliances and gas lines. The customer's limited
2 income often makes paying for the necessary repairs difficult and sometimes
3 impossible, and it leaves the customer with no remaining money to install the
4 energy efficiency measures identified by the audit. If the customer does not have
5 the funds to repair the appliance or the gas line, the service must be disconnected.
6 When potential customers fear that the WarmWise-A&R BPI audit may result in
7 disconnection of service, they are less likely to participant in the BPI audit. The
8 safety rebate would provide some financial assistance to help the customer make
9 the emergency repair and thereby enable them to better afford the installation of
10 the audit recommended energy efficiency measures.

Q. Please explain the second change or enhancement that Columbia may consider
12 within the WarmWise-A&R program.

A. The second example that Columbia may consider as a potential enhancement is to
14 partner with third party lending organizations to provide customers who
15 participate in the WarmWise-A&R program financial assistance for the
16 recommended measures and then utilize Columbia's billing system for the loan
17 repayment. Columbia is pursuing conversations with several third party entities to
18 see if such an arrangement is viable. Unfortunately, when such financial assistance
19 funds become available, they are often available for a limited time and it is difficult
20 to obtain Commission approval under the tight time frame.

1 Q. What is the third example of a potential enhancement or change that Columbia
2 may choose to make to the WarmWise-A&R program?

3 A. Based on experience with other programs, understanding customer needs, and in
4 light of the changing marketplace for energy efficiency products and services,
5 Columbia may find it appropriate to modify the upfront rebate levels and or the
6 qualifying measures in order to maximize the impact of the WarmWise-A&R
7 program.

8 Q. Please explain why Columbia seeks to obtain regulatory permission to make
9 program modifications as needed on a going forward basis without obtaining
10 further Commission approval for each change or enhancement?

11 A. Columbia believes that allowing it to make the types of changes identified above,
12 within the annual budget for the program, will provide Columbia with the flexibility
13 to modify components of the WarmWise-A&R program to meet changing customer
14 demand and to take advantage of opportunities in the marketplace so as to ensure
15 the program's success. Requiring Columbia to seek prior regulatory approval for
16 each individual change is both burdensome and in most cases slows down – or
17 could even prevent - the implementation of that particular change which may
18 impair the success of the program.

1 **3c. Distribution System and Service Improvements**

2 Q. In addition to Columbia's customer service performance and its universal service
3 and customer programs, can you provide the Commission with any other basis for
4 evaluating the efficiency of Columbia's management of its business?

5 A. Columbia is focused on delivering safe, efficient, reliable, and quality service to its
6 customers and Columbia continuously strives to make improvements and
7 investments in its construction and operation areas. In addition to efforts like the
8 multi-year contracts that Columbia negotiated with its pipeline contractors that I
9 described above, I will highlight here in bullet fashion a few examples of recent
10 changes made that have improved system operations and customer delivery
performance:

- 12 • Reduce the number of open Type-2 leaks in the Columbia distribution
13 system as measured by the annual Federal DOT report. At the end of 2007
14 Columbia reported a total of 3,755 open Type-2 leaks in its Distribution
15 System. As of August 1, 2012 Columbia had 2,035 open Class-2 leaks, which
16 equates to a nearly 45% reduction in the last 5 years. In addition, as
17 discussed by Company witnesses Cote and Kitchell, Columbia intends to
18 continue to accelerate its Type-2 leak repairs in order to further reduce the
19 backlog of open Type-2 leaks.
- 20 • Increase Columbia's 60 minute or less Emergency Response Rates. Since
21 2006, Columbia has undertaken a very structured approach to improving its

1 emergency response times and made another significant process
2 improvement in 2011. The results of Columbia's effort have been significant
3 as demonstrated by Company witness Kitchell.

4 • Improve Columbia's locating performance and excavator outreach as
5 measured by Third Party Damage per thousand locates. As detailed by
6 Company witness Cote, since 2006, Columbia has undertaken a
7 comprehensive process designed to improve locating performance and
8 reduce third-party damage to Company facilities. These efforts have
9 resulted in a 57% reduction in third party damage on the Columbia system
10 between 2006 and 2012. In addition, Columbia is embarking on a more
11 extensive educational program for the public with an emphasis on school
12 children.

13 Company witnesses Kitchell and Cote (Columbia Statements No. 7 and 8) testify
14 about the details of these operational improvements in their testimonies as well.

15 **3d. Automated Meter Reading Devices**

16 Q. Has Columbia implemented any other improvements which enhance the customer's
17 experience?

18 A. In addition to the above-described improvements which were consciously identified
19 and purposefully driven by Columbia's management team, a most notable
20 improvement is the Company's emerging success with its Automated Meter
21 Reading program. In Columbia's last rate case, it included costs associated with the

1 installation of Automated Meter Reading devices (AMRs) on its residential and
2 small commercial accounts throughout Columbia's service territory. As Columbia
3 indicated in its testimony in that case, moving to AMRs would enable Columbia to
4 provide customers with actual meter readings each month rather than its previous
5 practice of providing an actual bill one month and an estimated bill the following
6 month.

7 Q. Please provide a status update on the implementation of AMRs.

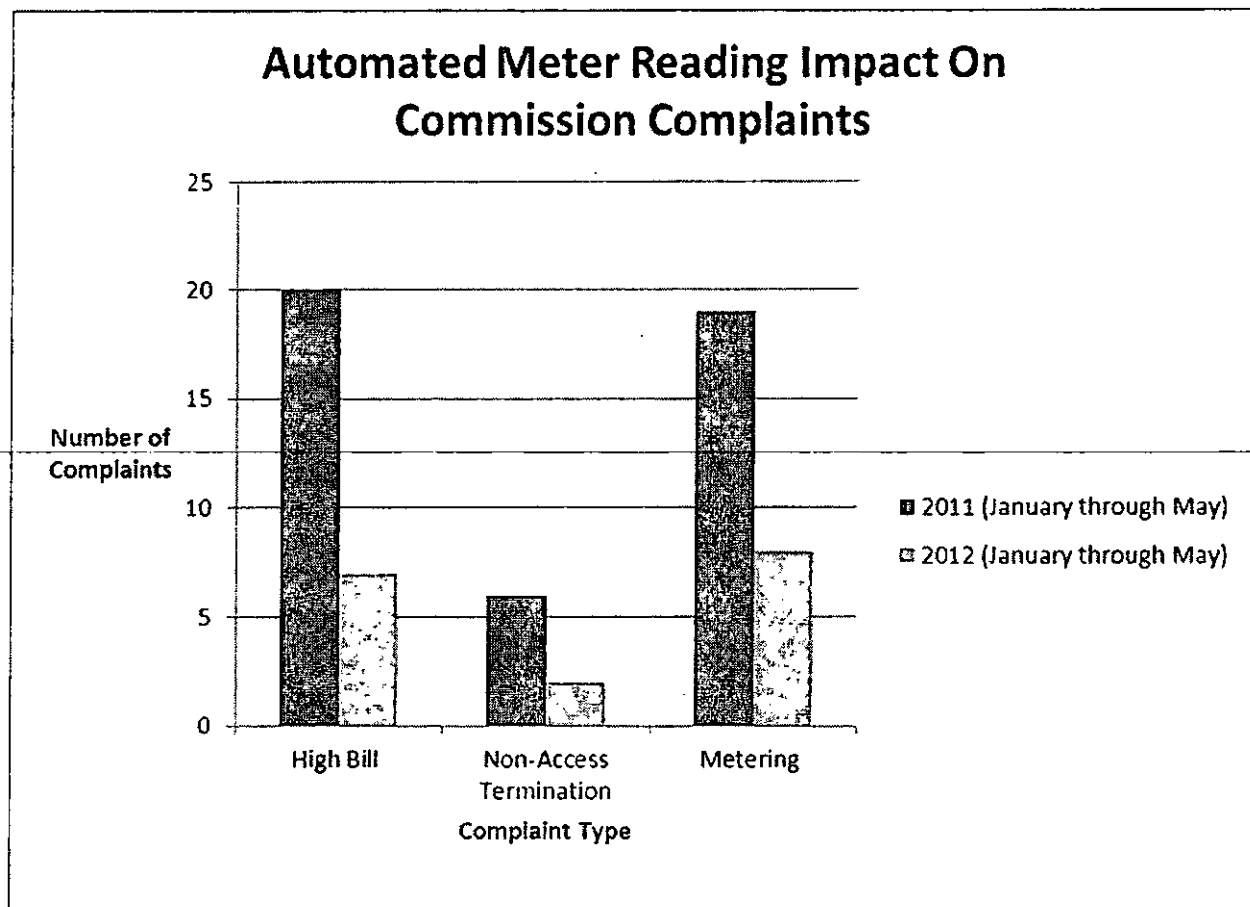
8 A. As of the end of September 2012, Columbia has successfully installed AMR devices
9 on roughly 99% of its residential and small commercial meters across its service
10 territory. On the western side of Columbia's service territory, customers with AMR
11 technology began receiving actual meter readings each month as of March 2012,
12 while customers in the Eastern portion of Columbia's service territory are moving
13 to actual monthly bills beginning in December 2012.

14 Q. Has the project had any demonstrable impact on customer service?

15 A. Yes, AMR technology has enhanced customer satisfaction in three areas: Improved
16 accuracy of the customer's meter reading and billing; elimination of estimated bills;
17 and reduction to the number of complaints related to high bills and non-access.
18 Columbia routinely tracks metrics related to meter reading and billing complaints.
19 As shown in Figure 5 below, based on internal data regarding Commission informal
20 complaints recorded by Columbia through June 2012, compared to June 2011,
21 Columbia experienced the following results:

- 65% decrease in high bill complaints.
- 50% decrease in non-access complaints.
- 50% decrease in metering type complaints.

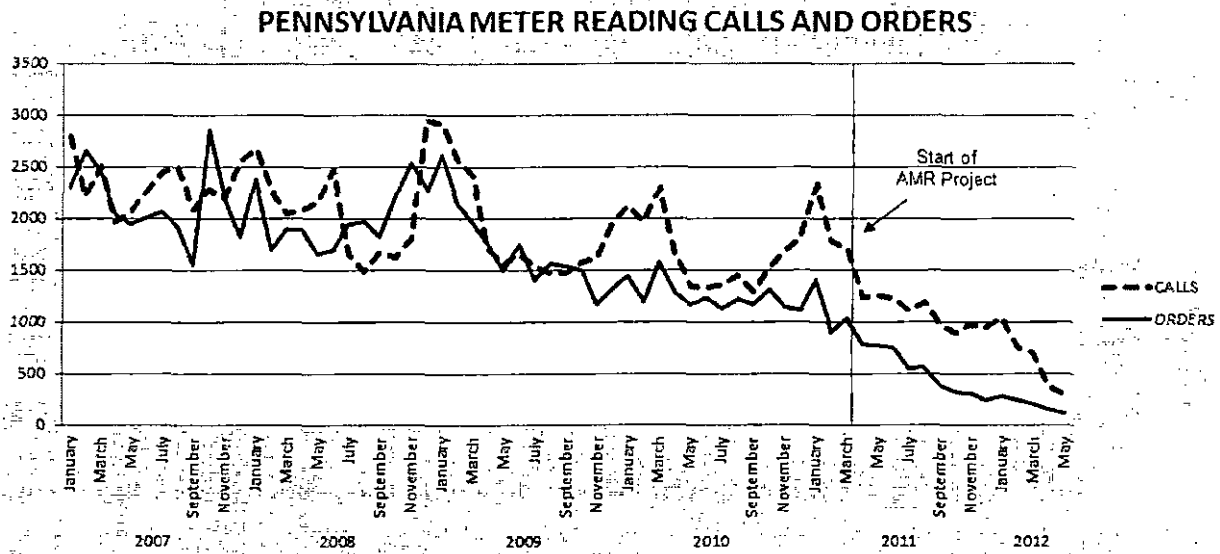
Figure 5



Q. Has Columbia experienced improvements in other areas of its operations as a result of the AMR initiative?

1 A. Since Columbia began the mass deployment of AMR devices in March of 2011,
2 there has been a significant decrease in the number of meters not read at the six
3 and twelve month intervals. According to the Commission's 2011 Quality of Service
4 Report, Columbia's average number of residential meters that were not read
5 monthly at the six month interval totaled 551. As of the end of May 2012,
6 Columbia's monthly average was 121. Likewise, the average number of residential
7 meters not read and out of compliance at the twelve month interval was 204. As of
8 the end of May 2012, that number has been reduced to 40. Besides improvements
9 in meter reading compliance and billing accuracy, the AMR project has created
10 additional efficiencies within Columbia's service department. Since starting the
11 AMR project, Columbia has seen a gradual reduction in the number of meter
12 reading orders generated monthly to investigate prior readings. Reducing these
13 orders has allowed more time for Columbia's service personnel to perform more
14 critical work such as connections, leak investigations, and other customer service
15 work that will better serve and satisfy our customers. Along with a reduced
16 number of investigation orders, Columbia has experienced a decrease in the
17 number of customer phone contacts to its customer contact center regarding meter
18 reading activity, as shown in Figure 6 below.

Figure 6



4. Introduction of Witnesses

Q. Please introduce Columbia's witnesses and describe their testimony.

- Company witness Amy Efland, the Senior Forecast Analyst for NiSource Corporate Services Company ("NCSC") provides demand forecasting services for Columbia. In Columbia Statement No. 2, she explains how residential and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Bell's testimony (Columbia Statement No. 3) and Exhibit 3 Schedule 4. Company witness Efland also explains the projection of the future test year and fully forecasted rate year customer and load growth and comments on the residential consumption per customer.

- 1 • Company witness Melissa Bell is a Lead Regulatory Analyst for NCSC. She provides
2 support for regulatory filings for Columbia. In Columbia Statement No. 3,
3 Company witness Bell supports the Company's requested increase in base rates by
4 providing detailed information on the Company's pro forma operating revenues for
5 the historical test year and for the twelve months ending June 30, 2014 (Fully
6 Forecasted Rate Year).
- 7 • Company witness Jeffery Gore is the Manager of Regulatory Strategy and Support
8 for NCSC and provides regulatory accounting and strategy services to Columbia. In
9 Columbia Statement No. 4, witness Gore presents Columbia's cost of service and
10 quantifies the revenue deficiency based on operating costs and revenues, as
11 adjusted. Company witness Gore supports Columbia's Cost of Service Operating
12 and Maintenance ("O&M") expenses and he supports the Company's rate base
13 claim.
- 14 • Company witness John J. Spanos is a Vice President in the Valuation and Rate
15 Division of Gannett Fleming, Inc. In Columbia Statement No. 5, witness Spanos,
16 supports the depreciation study Gannett Fleming prepared for gas plant of
17 Columbia.
- 18 • Company witness Nancy Krajovic is Columbia's Director of Rates and Regulatory
19 Affairs. In Columbia Statement No. 6, she provides detail and support about the
20 methods and assumptions used to develop the Historic Test Year, Future Test Year,

1 and the Fully Forecasted Rate Year Rate Base as presented in Exhibits 8 and 108
2 (Rate Base), respectively.

- 3 • Company witness Robert Kitchell is the Vice President and General Manager for
4 Columbia. In Columbia Statement No. 7, Company witness Kitchell describes the
5 division of staff between the traditional field operations department and the newly
6 created Pipeline Safety and Compliance Organization that is being overseen by
7 Company witness Cote. Company witness Kitchell also provides testimony in
8 support of some of the initiatives Columbia has previously undertaken to improve
9 its overall operations, and he testifies to Columbia's incremental O&M needs
10 associated with the Company's increased level of capital investment in 2012 and
11 beyond.

-
- 12 • Company witness Danny Cote is the Vice President of Pipeline Safety and
13 Compliance for the gas distribution segment of NiSource Inc., and he is responsible
14 for all leadership and direction for the newly created Pipeline Safety and
15 Compliance Organization for Columbia. In Columbia Statement No. 8, Company
16 witness Cote describes Columbia's distribution system, its historic operating
17 performance, the initiatives that it has undertaken to improve its overall safety and
18 compliance efforts, including the creation of Columbia's Pipeline Safety and
19 Compliance Organization, new pipeline safety rules that generate a need for
20 increased O&M activity, and the planned system enhancements to Columbia's 2013

1 operations. He also testifies about Columbia's ongoing replacement activities and
2 supports Columbia's future test year and fully forecasted rate year plant additions.

- 3 • Company witness John Skirtich is a consultant with substantial experience in utility
4 regulatory accounting. In Columbia Statement No. 9, witness Skirtich presents the
5 Class Cost of Service Studies by rate case at present and proposed rates, and an
6 analysis supporting minimum charges for all rate schedules.

- 7 • Company witness Paul Moul is the Managing Consultant at the firm P. Moul &
8 Associates, an independent financial and regulatory consulting firm. In Columbia
9 Statement No. 10, Company witness Moul presents detailed testimony and
10 documentation and a recommendation concerning the appropriate cost of common
11 equity and overall rate of return that the Commission should recognize in the
12 determination of the revenues that Columbia should be given an opportunity to
13 earn as a result of this base rate case. His recommendation is supported by detailed
14 financial data and an in-depth explanation of the application of the various
15 financial models upon which he relies.

- 16 • Company witness Panpilas W. Fischer is the Manager of Income Taxes at NCSC
17 and she provides Tax Accounting services for Columbia. In Columbia Statement
18 No. 11, Company witness Fischer supports Columbia's income tax and other tax
19 expense included in the cost of service. She provides detail about both federal and
20 state income tax recovery, reduction of rate base for deferred income taxes, as well

1 as a reduction to tax expense resulting from the Company's 2008 change in tax
2 method of accounting for repairs.

- 3 • Company witness Summer D. Cogar is Special Studies Accounting Manager for
4 NCSC and is responsible for overseeing the accounting with regard to the costs for
5 services that are billed by NCSC to NCSC affiliates including Columbia. In
6 Columbia Statement No. 12, Company witness Cogar testifies about NCSC and the
7 role it serves within NiSource Inc. and the services it provides to Columbia. She
8 testifies to the annualized level of fixed, known and measurable NCSC charges
9 applicable to Columbia in the historic test year, and as adjusted for the fully
10 forecasted rate year. In supporting the annualized expense levels, she provides
11 information pertaining to the types of costs that have been allocated to Columbia

12 and the mechanism for determining the appropriate allocation of each type of cost.

- 13 • Company witness Richard Fontaine is Vice President, Financial Transformation for
14 NCSC and he is responsible for leading the "NiFit" project which is designed to
15 upgrade financial processes and information systems across all of the NiSource
16 companies, including Columbia. In Columbia Statement No. 13, Company witness
17 Fontaine provides the rationale behind the NiFiT project, the benefits from and
18 project timeline for NiFiT, and the expected capital and O&M costs to Columbia for
19 NiFiT.
- 20 • Company witness Deborah D. Schmelzer is Project Manager for NCSC. In
21 Columbia Statement No. 14, she testifies about the past and anticipated changes in

1 major accounting procedures since the previous rate case, the OPEB base rate
2 reconciling mechanism, and the amortization of the deferred NCSC OPEB-related
3 costs.

4 • Company witness Paula Strauss is Director of Regulatory Strategy and Support for
5 NCSC and provides regulatory strategy services to Columbia including rate design
6 and analysis. In Columbia Statement No. 15, Company witness Strauss presents
7 evidence and support for Columbia's rate design, proposed rates and bill impacts.
8 In accordance with the Commission's recommendation in its order in Columbia's
9 last base rate case, Company witness Strauss provides three different options for
10 residential rate designs, including the Company's Revenue Normalization
Adjustment that is Columbia's filed proposal. All three rate designs are designed to
12 provide Columbia with more certainty in the recovery of revenues from residential
13 customers. She also testifies about the proposed commercial and industrial base
14 rates as well as the Gas Procurement Charge ("GPC"). Finally, Witness Strauss
15 testifies to Columbia's proof of revenue and bill impacts.

16 • Company witness Shirley Bardes-Hasson is Manager of Regulatory for Columbia
17 and is responsible for managing regulatory activity before the Commission,
18 including ensuring timely, accurate regulatory filings as well as monitoring
19 regulatory cases making recommendations for Company participation in those
20 cases when warranted. In Columbia Statement No. 16, Company witness Bardes-

1 Hasson explains and supports the tariff changes that the Company seeks to make in
2 this proceeding.

- 3 • Company witness Thomas C. Heckathorn is the Director of Transportation and
4 Supplier Services at NCSC. In that capacity, he directs the Choice Service for
5 Columbia and is responsible for managing Columbia's capacity assets. In Columbia
6 Statement No. 17, Company witness Heckathorn testifies about several
7 modifications to Columbia's tariff and processes that are being made as a result of
8 discussions with the natural gas suppliers that had intervened in Columbia's last
9 rate case.

- 10 • Company witness Rachel Ford is Director of Communications for Columbia. In
11 Columbia Statement No. 18, Company witness Ford explains the Company's

12 proposed new Education Program, "Count on Columbia." The goal of this new
13 Program is to inform and educate Columbia's consumers about the positive
14 benefits that the infrastructure replacement program and subsequent base rate
15 adjustments have on natural gas safety, affected communities and the economy.
16 The "Count on Columbia" program will also provide important information to
17 school children regarding natural gas safety issues as well as call-before-you-dig.
18 The proposed Program will not only expand upon current outreach efforts, but also
19 dovetail with Columbia's annual "RP 1162" public awareness campaign for pipeline
20 operators that is required by federal regulation.

- 1 • Company witness Erich Evans is the Director of Regulatory Strategy for NCSC and,
2 in Columbia Statement No. 19, he supports the Company's proposed Pilot New
3 Area Service rider, which is designed to promote mainline extensions to customers
4 who might not otherwise be able to fund the upfront investment that would be
5 required to justify certain extensions.

6 Q. Are you sponsoring any exhibits in this proceeding?

7 A. Yes. I am sponsoring Exhibit No. 13, Schedule 3 which cross references the
8 standard filing requirements with the corresponding Exhibit and Schedule in this
9 filing for both the historical and future test year.

10 Q. Does this conclude your prepared direct testimony?

A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

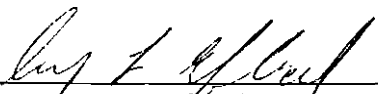
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Amy L. Efland, being Senior Forecast Analyst of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 2 and 102-R are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Amy L. Efland

2-13-13

Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
AMY L. EFLAND
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Amy L. Efland and my business address is 200 Civic Center Drive,
3 Columbus, OH 43215.

4 Q. By whom are you employed and in what capacity?

5 A. I am a Senior Forecast Analyst for NiSource Corporate Services Company.

6 Q. What are your responsibilities as Senior Forecast Analyst?

7 A. I assist with the development of short-range and long-range forecasts of customers,
8 energy consumption and peak demand for seven NiSource gas distribution
9 companies, including Columbia Gas of Pennsylvania ("Columbia" or the
10 "Company") and one NiSource electric company. I also assist with other business
11 related analyses and forecasts.

12 Q. What is your educational and professional background?

13 A. I attended Earlham College where I earned a Bachelor of Arts Degree in Economics
14 and Miami University where I earned a Master of Arts Degree in Economics. From
15 1997 to 2002, I worked as a forecast analyst for Cinergy, assisting with the
16 production of the gas and electric long-term forecasts of customers, energy
17 consumption and peak demand for the Cinergy (PSI, ULH&P and CG&E)
18 territories. I was promoted to Lead Analyst in 2002, a position I held until I left
19 Cinergy in 2005. From 2005 to 2006, I worked as a Senior Forecasting Analyst
20 with Limited Brands/Victoria's Secret Direct. I provided analysis and
21 recommendations surrounding circulation levels of catalogues and assisted with
22 catalogue messaging relating to marketing offers. From 2006 to 2008, I worked as

1 a Senior Marketing Analyst for JP Morgan Chase where I was responsible for the
2 development of test designs for consumer and business banking marketing
3 programs. I joined NiSource in 2008 as a Senior Forecast Analyst.

4 Q. Have you testified before this or any other Commission?

5 A. Yes, I have provided direct testimony related to weather normalization and
6 customer usage trends before the Pennsylvania Public Utility Commission
7 ("Commission"), Docket Nos. R-2009-2149262, R-2010-2215623 and the Kentucky
8 Public Service Commission, Case No. 2009-00141.

9 Q. What test years will you be addressing in this testimony?

10 A. I will be addressing the twelve-month period ending May 31, 2012 as the Historic
11 Test Year, the twelve-month period ending May 31, 2013 as the Future Test Year as
12 well as the twelve-month period ending June 30, 2014 as the Fully Forecasted Rate
13 Year.

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

15 A. I will explain how residential and commercial sales are normalized for weather.
16 The results of the normalization procedure are contained in Company witness Bell's
17 testimony (Columbia Statement No. 3) and Exhibit 3 Schedule 4. I will also explain
18 the projection of the Future Test Year and Fully Forecasted Rate Year customer and
19 load growth and comment on the residential consumption per customer.

20 Q. Please explain the weather normalization procedure.

21 A. For each month of the Historic Test Year for the residential and commercial classes,
22 actual billing month sales per customer is separated into base-load and

1 temperature-sensitive load. Temperature-sensitive load is then scaled by the ratio
2 of normal to actual heating degree days ("HDD") to derive normal temperature-
3 sensitive load per customer. The normal temperature-sensitive load per customer
4 is then added to the base-load per customer to arrive at the normal sales per
5 customer. This value is then multiplied by the customer count to derive the normal
6 sales.

7 Q. What data sources did you use for your calculations?

8 A. I used company billing records to obtain monthly customer counts and billed sales.
9 The temperatures used to calculate HDD were obtained from National Weather
10 Service weather stations throughout the Company's service territory. Due to the
11 geographical dispersion of Columbia's customers, temperature data from multiple
12 weather stations is used. A weighted average HDD for the Company is calculated
13 using the percent of residential heating customers assigned to each station as a
14 weight for that station.

15 Q. How does the procedure calculate base load?

16 A. The procedure assumes no temperature sensitive (heat) load in July and August.
17 For September, no temperature sensitive (heat) load is assumed when total load per
18 customer per day (Total Load/Customer/Day) is less than July and/or August. The
19 base load per customer per day is calculated by taking the average of the two lowest
20 observed values from the months of July through September.

21 Q. How does the procedure weather normalize monthly sales?

1 A. First, the monthly base load per customer is determined. This equals the lesser of
2 the base load per customer per day multiplied by the days in the billing cycle ((base
3 load/customer/day)*days in billing cycle) or the monthly total load per customer.
4 Second, monthly heat load per customer is calculated. Heat load per customer
5 equals the total load per customer minus the base load. Third, the heat load per
6 customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD.
7 Finally, normal load per customer is calculated by adding the base load per
8 customer to the normal heat load per customer. Total monthly normalized usage is
9 generated by multiplying monthly customers by the monthly normal load per
10 customer. This calculation for the Historic Test Year is prepared separately for
11 residential and commercial customers and the results are presented in Exhibit 10,
12 Schedule 8.

13 Q. Has the procedure for normalizing weather changed from the last rate filing?

14 A. No—not other than updating the historic averages to include the most recent 20
15 year history. Normal weather in this case is defined in this filing as the average
16 HDD for the 20 years ended 2011. The previous filing defined normal weather as
17 the 20-year average ending in 2009. In all other respects, the normalization
18 procedure is the same.

19 Q. Why is Columbia proposing the 20-year average?

20 A. The settlement of the Company's 2011 base rate proceeding at Docket No.
21 R-2010-2215623 designed rates based upon the Company's proposed throughput
22 volumes, which reflected the Company's use of the 20-year average. The Company

1 proposes to continue to use this procedure because an analysis of weather data
2 shows that a rolling 20-year average is a superior measure to a rolling 30-year
3 average. Table 1 below illustrates that as a predictor of one-year-ahead weather, the
4 20-year average outperforms the 30-year average in 74% of the most recent 31
5 years. The 25-year average outperforms the 30-year average in 61% of the most
6 recent 31 years. Table 1 also illustrates that the 20-year average has consistently
7 lower mean absolute error compared to both the 25-year and 30-year averages.

8 A further test is made analyzing performance over five year periods. In Table 2, the
9 averages are used each year to predict each five year period for the 5-years ended
10 1985 through the five years ended 2011. In this analysis, the performance of the
11 20-year and 25-year averages were compared to the 30-year average. The average
12 with the smaller difference over the 5-year period was judged superior. In this
13 analysis, the 20-year average out performs the 30-year average in 81% or 22 out of
14 the 27 periods. The 25-year average out performs the 30-year average in 63% or 17
15 out of the 27 periods. When considering the most recent 10 periods, the 20-year
16 average outperforms the 30-year average in 100% or all of the 10 periods. The 25-
17 year average out performs the 30-year 70% of the time during this same period.

18 Table 3 demonstrates that stability is not sacrificed when using a 20-year average.
19 The average annual change for the 20-year average is 0.4% while the average
20 annual change for both the 25-year and 30-year averages is 0.3%. The 20-year
21 normal is not only a better predictor, but also a more dynamic measure that is
22 better able to react more quickly to change because it replaces 5% of the data each

year rather than the 3% replaced with the 30-year average. In conclusion, the 20-year measure performs better compared to the 30-year in both the year ahead analysis and the five year analysis, and is both a better predictor and a more dynamic measure when compared to the 30-year average.

Table 1
Weather Averages as Predictors
Moving Averages used to Predict Following Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days				Absolute Error			Better 1-year predictor		Better 1-year predictor	
	Actual	20-yr Average	25-yr Average	30-yr Average	20-yr Average	25-yr Average	30-yr Average	20-yr Average	30-yr Average	25-yr Average	30-yr Average
1980	6010	5877	5854	5766							
1981	6219	5887	5873	5790	342	365	453	x		x	
1982	5915	5880	5890	5811	28	42	125	x		x	
1983	5568	5848	5873	5831	312	322	243		x		x
1984	6064	5860	5884	5853	216	191	233	x		x	
1985	5236	5831	5862	5845	624	648	617		x		x
1986	5571	5818	5844	5839	260	291	274	x			x
1987	5456	5796	5820	5838	362	388	383	x			x
1988	5892	5791	5807	5835	96	72	54		x		x
1989	5724	5778	5803	5833	67	83	111	x		x	
1990	5071	5737	5773	5808	707	732	762	x		x	
1991	4908	5692	5737	5771	829	865	900	x		x	
1992	5558	5680	5723	5755	134	179	213	x		x	
1993	5455	5693	5701	5730	225	268	300	x		x	
1994	5719	5709	5691	5726	26	18	11		x		x
1995	5427	5706	5672	5713	282	264	299	x		x	
1996	6005	5704	5680	5719	299	333	292		x		x
1997	5641	5681	5673	5711	63	39	78	x		x	
1998	4590	5601	5650	5664	1091	1083	1121	x		x	
1999	5166	5560	5640	5637	435	484	498	x		x	
2000	5403	5529	5637	5621	157	237	234	x			x
2001	5385	5488	5610	5606	144	252	236	x			x
2002	5304	5457	5579	5590	184	306	302	x			x
2003	5825	5470	5564	5611	368	246	236		x		x
2004	5329	5433	5538	5608	141	235	282	x		x	
2005	5564	5450	5520	5611	131	26	44		x	x	
2006	5175	5430	5478	5582	275	345	436	x		x	
2007	5295	5422	5453	5555	135	183	287	x		x	
2008	5526	5404	5452	5533	104	73	29		x		x
2009	5447	5390	5427	5515	44	5	86	x		x	
2010	5400	5406	5433	5495	10	27	115	x		x	
2011	5421	5432	5427	5468	15	12	74	x		x	
					Mean Absolute Error			Frequency of Lowest Absolute Error			
1981-2011					261	278	301	23	8	19	12
2002-2011					141	146	189	7	3	7	3
					Relative Frequency of Lowest Error						
1981-2011					74%	26%	61%	39%			
2002-2011					70%	30%	70%	30%			

Table 2
Weather Averages as Predictors
Moving Averages used to Predict the Following Five Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days				Five Year Sum of Errors			Better 5-year predictor		Better 5-year predictor	
	Actual	20-yr Average	25-yr Average	30-yr Average	20-yr Average	25-yr Average	30-yr Average	20-yr Average	30-yr Average	25-yr Average	30-yr Average
1980	6010	5877	5854	5766							
1981	6219	5887	5873	5790							
1982	5915	5880	5890	5811							
1983	5568	5848	5873	5831							
1984	6064	5860	5884	5853							
1985	5236	5831	5862	5845	-382	-269	173		x		x
1986	5571	5818	5844	5839	-1080	-1011	-597		x		x
1987	5456	5796	5820	5838	-1506	-1555	-1159		x		x
1988	5892	5791	5807	5835	-1022	-1146	-937		x		x
1989	5724	5778	5803	5833	-1422	-1543	-1386		x		x
1990	5071	5737	5773	5808	-1442	-1594	-1512	x			x
1991	4908	5692	5737	5771	-2040	-2167	-2146	x			x
1992	5558	5680	5723	5755	-1827	-1947	-2038	x		x	
1993	5455	5693	5701	5730	-2239	-2320	-2458	x		x	
1994	5719	5709	5691	5726	-2179	-2305	-2454	x		x	
1995	5427	5706	5672	5713	-1619	-1800	-1975	x		x	
1996	6005	5704	5680	5719	-297	-519	-693	x		x	
1997	5641	5681	5673	5711	-151	-368	-529	x		x	
1998	4590	5601	5650	5664	-1083	-1125	-1268	x		x	
1999	5166	5560	5640	5637	-1715	-1625	-1803	x		x	
2000	5403	5529	5637	5621	-1725	-1557	-1762	x		x	
2001	5385	5488	5610	5606	-2334	-2217	-2412	x		x	
2002	5304	5457	5579	5590	-2557	-2519	-2706	x		x	
2003	5825	5470	5564	5611	-924	-1165	-1236	x		x	
2004	5329	5433	5538	5608	-553	-955	-937	x			x
2005	5564	5450	5520	5611	-240	-778	-696	x			x
2006	5175	5430	5478	5582	-241	-855	-835	x			x
2007	5295	5422	5453	5555	-98	-705	-760	x		x	
2008	5526	5404	5452	5533	-461	-933	-1165	x		x	
2009	5447	5390	5427	5515	-159	-681	-1035	x		x	
2010	5400	5406	5433	5495	-405	-756	-1212	x		x	
2011	5421	5432	5427	5468	-60	-301	-820	x		x	
					Mean Error			Frequency of Lowest Error			
1985-2011					-1102	-1286	-1347	22	5	17	10
2002-2011					-570	-965	-1140	10	0	7	3
								Relative Frequency of Lowest Error			
								81%	19%	63%	37%
								100%	0%	70%	30%

1

2

Table 3

Stability of Weather Averages				
Annual Change in Averages 1981-2011				
Absolute Values				
Columbia Gas of Pennsylvania				
	20-yr Average	25-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	0.3%	6.1%
Maximum	1.4%	0.8%	0.8%	18.6%

Q. Please explain the methodology employed for developing the forecasted number of customers and customer usage for the Future Test Year and the Fully Forecasted Rate Year.

A. Development of the forecasting methodology is presented in the following summary. This method was used to develop both the Future Test Year and the Fully Forecasted Rate Year. Price information included in the models is from the company's databases, average efficiency data is from Itron Inc, a national utility consulting firm. The economic variables and deflator information is from IHS Global Insight, Inc, a data consultant and weather data is provided by Televant, a weather consulting service

Residential and Commercial Customers

- Total new customer additions are forecasted for the initial three years of the forecast by the New Business Team. Choice customers are calibrated to the most recently observed level and the forecast is set to the observed saturation percentage.

- 1 • Traditional transportation customers = existing transportation customers + new
- 2 customers identified by the Large Customer Relations group.
- 3 • Existing customers are forecasted using the latest historical level. The forecast is
- 4 calculated by applying an attrition rate calculated using recent historical data. The
- 5 attrition rate is applied to the latest existing level of customers at the time the
- 6 forecast is being prepared. The attrition rate used for the Future Test Year and
- 7 Fully Forecasted Rate Year is 0.4% for Residential and 1.5% for Commercial.
- 8 • Total customers = existing customers + new customers – attrition customers
- 9 • Sales customers = total customers – Choice customers – traditional (commercial)
- 10 transportation customers

11 **Residential Dth/customer**

12 Residential use per customer is forecasted with an econometric model that incorporates
13 real price, an average efficiency variable, real per capita income, and heating degree
14 days.

15 **Residential Volume**

- 16 • Dth is forecasted for existing and new construction customers

$$17 \quad \text{Dth} = \text{customers} * \text{Dth/customer}$$

- 18 • Choice Dth forecasted as

$$19 \quad \text{Choice Dth} = \text{customers} * \text{Dth/customers}$$

- 20 • Sales Dth forecasted as residual

$$21 \quad \text{Sales Dth} = \text{Dth} - \text{Choice Dth}$$

22 **Commercial Dth/customer**

- Commercial use per customer is forecasted with an econometric model that incorporates real price, real gross county product, average efficiency variable, and heating degree days.

Commercial Dth

- Dth is forecasted for existing and new construction customers

$$\text{Dth} = \text{customers} * \text{Dth/customer}$$

- Choice Dth is forecasted as

$$\text{Choice Dth} = \text{customers} * \text{Dth/customers}$$

- Non-Choice transportation Dth for large commercial customers is forecasted by the Large Customer Relations group. Non-Choice transportation Dth for smaller commercial customers is forecasted as the trend in the forecast for total commercial use per customer adjusted for the forecast for large customers.

- Sales Dth forecasted as residual

$$\text{Sales Dth} = \text{Dth} - \text{Choice Dth} - \text{non-choice transportation}$$

Industrial Volume

- The Large Customer Relations group generates a forecast of volume for large industrial customers through a survey. The Forecasting Group uses an econometric model adjusted for the forecast for large customers. The econometric model incorporates real price, manufacturing employment, industrial production, and heating degree days. The total industrial volume forecast is the sum of the large industrial forecast and the all other industrial forecast. The industrial forecast

1 provided from the Large Customer Group makes up 92% of the total industrial
2 forecast.

- 3 • The survey and small customer analysis provides the sales/transportation split of
4 Dth, and any additional transportation Dth is forecasted with the trend from the
5 econometric model adjusted for the forecast for large customers.

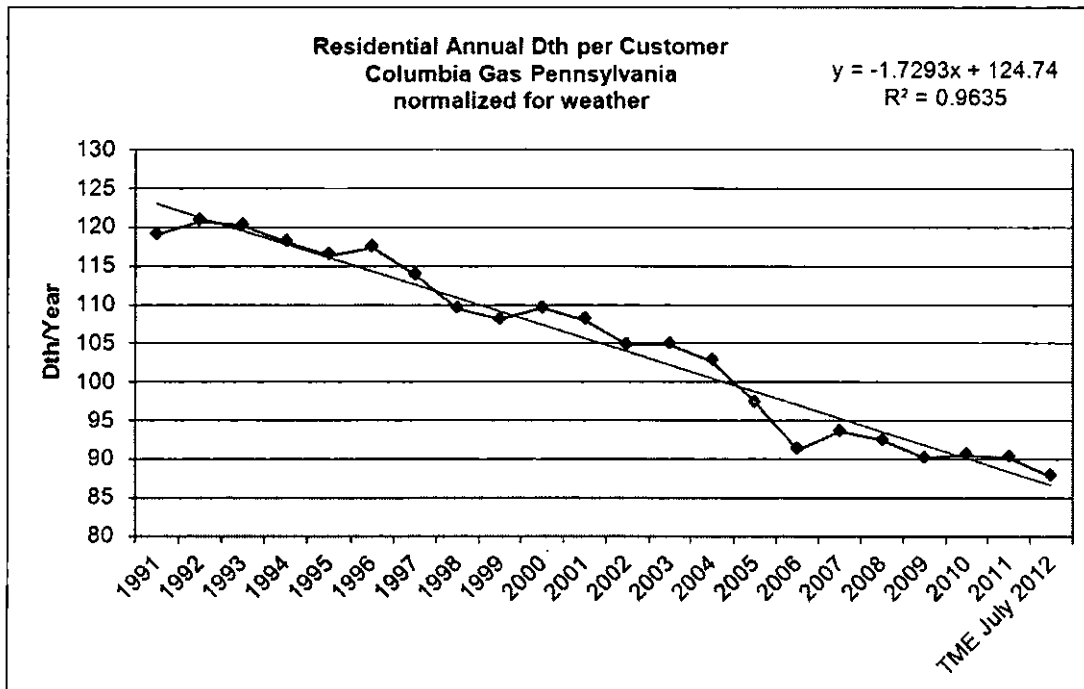
6 Q. Please discuss the past performance of the forecast.

7 A. Residential and commercial forecast models are updated annually with the most
8 current data. An internal review of forecast performance occurs on a regular basis.
9 Variances for the residential and commercial predictions are calculated and
10 assessed in order to measure accuracy. The average annual one year weather
11 normalized variance for the residential models is 0.1%. For commercial, the
12 average one year variance is 0.1% weather normalized.

13 Q. Describe Columbia's recent trends related to residential use per customer.

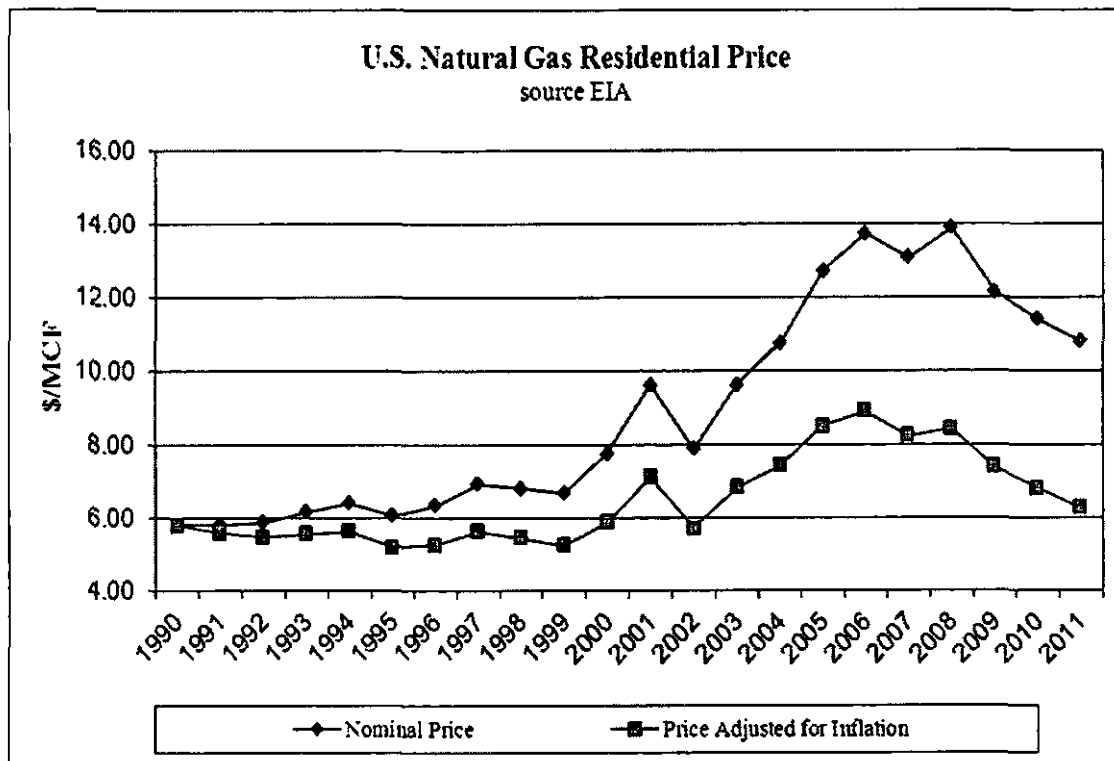
14 A. From 2002 to 2011, weather normalized usage for residential heating customers
15 has fallen 13.9% from 104.8 Dth per year to 90.2 Dth per year. From 2007 to 2011
16 use per customer dropped 3.6% from 93.6 Dth to 90.2 Dth. The data shows that
17 there are only a few years with an increase in use. All of these periods were followed
18 by decreases, indicating that these points were not representative of the overall
19 trend. The most recent example of this are the years 2010 and 2011. Usage appears
20 to flatten out during this period. However, when taking into account the most
21 current twelve month period ending July 2012 (TME July 2012), there is a decline
22 of 2.6% from 2011. Usage falls from 90.2 Dth in 2011 to 87.8 Dth for the twelve

1 month period ending July 2012, further supporting the overall trend and decline in
2 usage.



3
4
5 Q. What factors have caused the reduction in residential customer usage?

6 A. Throughout most of the 1990s natural gas consumption per residential customer
7 was decreasing by 1% to 2% per year. This happened in spite of a relatively constant
8 nominal price illustrated in the graph below.



When adjusted for inflation, the price was actually decreasing during the 1990s. This conservation was a result of increased appliance efficiency and more efficient construction standards that followed the major price increases that occurred in the 1970s and 1980s. Annual conservation increased significantly as a result of the large natural gas price increases that occurred in the winters of 2000-2001, 2004-2005, and 2005-2006. With limited end uses for natural gas, increasing appliance efficiency, and higher building standards, the downward trend in consumption per customer will continue. Appliance choice will also affect the trend. Customers choosing high efficiency furnaces, energy efficient gas water heaters and electric

1 appliances such as electric water heaters, heat pumps and cooking ranges, will also
2 contribute to the downward trend.

3 Consumption per customer could also fall due to programs such as the
4 Pennsylvania Keystone Help Program which offers low interest loans to
5 homeowners seeking affordable financing to install energy efficiency retrofits.
6 Columbia's WarmWise Audits & Rebates Program ("WW A & R") formerly called
7 the Income Qualified Energy Efficiency Program ("IQEEP" is also expected to
8 further reduce use per customer. Specifically, the WW A & R program, which offers
9 income eligible customers free energy audits and upfront rebates towards audit
10 recommended installed energy efficiency measures, has doubled its participation
11 since the same time period last year. While Columbia does not consider the impact
12 of these programs in projecting its forecast, with increased consumer education
13 efforts promoting conservation programs it is reasonable that such programs will
14 further contribute to a decline in usage.

15 Q. Does this conclude your prepared direct testimony?

16 A. Yes it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

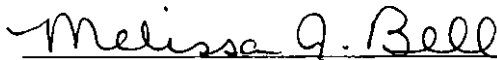
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
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Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Melissa J. Bell, being Lead Regulatory Analyst of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 3 is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. MJB-1 and MJB-2, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Melissa J. Bell

))))))))))

September 28, 2012

1 Q. Please state your name and business address.

2 A. Melissa J. Bell, 200 Civic Center Drive, Columbus, Ohio 43215.

3 Q. By whom are you employed and in what capacity?

4 A. I am employed by NiSource Corporate Services Company ("NCSC"), as a Lead Reg-
5 ulatory Analyst.

6 Q. What are your responsibilities as Lead Regulatory Analyst?

7 A. My responsibilities include providing support for regulatory filings for several
8 NiSource operating companies, including, but not limited to, Columbia Gas of
9 Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Ohio ("COH")
10 and Columbia Gas of Massachusetts ("CMA"). The types of filings include
11 quarterly gas cost adjustments, annual uncollectible expense and Percentage of
12 Income Payment Plan adjustments, as well as tariff updates. My monthly duties
13 include audit support, rate entry and verification, and other duties as assigned.

14 Q. What is your educational and professional background?

15 A. I graduated from The Ohio State University with a Bachelor of Science Degree in
16 Marketing in 1993. I began my career in the energy industry in 1996 when I joined
17 Columbia Gas of Ohio ("COH") as a Customer Service Representative, before
18 moving on in 1997 to COH's New Business Team as a Project Expediter. In 1999, I
19 left COH for a position at UtiliCorp Energy Solutions as a Commercial Account
20 Executive, until the sale of UtiliCorp Energy Solutions to Exelon Energy was
21 completed in 2000. At this time, I joined CSC Energy Solutions as a Tariff Analyst
22 until February 2003. In March 2003, I was employed by NiSource in the Gas
23 Transportation Services Department as a GTS Analyst II, providing sales support to
Major Account Representatives for Columbia Gas of Pennsylvania, Columbia Gas of

1 Maryland ("CMD") and Columbia Gas of Virginia ("CGV"), as well as support to
2 Natural Gas Suppliers and their customers. In December 2005, I accepted the
3 position as Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support
4 Department. I was promoted to my current position as Lead Regulatory Analyst in
5 2010. I have attended ratemaking workshops provided by the Southern Gas
6 Association, Deloitte LLP, Financial Accounting Institute and Regulatory Research
7 Associates.

8 Q. Have you previously testified before this or any other regulatory commission?

9 A. I have testified once before the Pennsylvania Public Utility Commission in a formal
10 complaint proceeding during my tenure as a GTS Analyst. I have not testified be-
11 fore any other regulatory commission.

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

13 A. I will sponsor and describe exhibits which support Columbia's proposed increase in
14 base rates, as illustrated in Exhibit 102 Schedule 3 Page 5, based on pro forma reve-
15 nues for the twelve months ending June 30, 2014 (Fully Forecasted Rate Year). The
16 exhibits were compiled in accordance with the Commission's regulations under Ti-
17 tle 52 Pennsylvania Code Section 53.51 et seq regarding Information Furnished
18 With The Filing of Rate Changes. Specifically, I am responsible for the preparation
19 and presentation of Exhibits 3 and 103 (Operating Revenues) with the exception of
20 Exhibit 103 Schedule 8 (Rate Design) which Company witness Strauss (Columbia
21 Statement No. 15) sponsors.

22 Q. What test years will you be addressing in this testimony?

1 A. I will be addressing the twelve-month period ending May 31, 2012 as the Historic
2 Test Year, the twelve-month period ending May 31, 2013 as the Future Test Year as
3 well as the Fully Forecasted Rate Year, twelve-month period ending June 30, 2014.

4 Q. Please explain the process that was undertaken to produce the number of bills used
5 to price revenue in this case.

6 A. The calculations made to determine the number of bills are found in Exhibit 3
7 Schedule 2 for the Historic Test Year and Exhibit 103 Schedule 2 for the Future Test
8 Year and Fully Forecasted Rate Year.

9 Active customer counts for each month of the Historic Test Year are accumulated by
10 rate schedule by customer class and shown in Column 1 of Exhibit 3, Schedule 2.
11 The bills are accumulated based on which rate schedule the customer is on at the
12 end of the Historic Test Year.

13 Adjustments resulting from large commercial or industrial customers either discon-
14 tinuing or adding service during the Historic Test Year are shown by customer in
15 Exhibit 3 Schedule 5 Pages 6 and 7, summarized on Exhibit 3 Schedule 5 Pages 1
16 and 2 and shown on Exhibit 3 Schedule 2 Column 2. New construction customers
17 beginning service during the Historic Test Year are shown on Exhibit 3 Schedule 5
18 Pages 4 and 5 and summarized on Exhibit 3 Schedule 2 Column 3. Customer attri-
19 tion that occurred during the Historic Test Year is shown on Exhibit 3 Schedule 5
20 Page 3 and summarized on Exhibit 3 Schedule 2 Column 4. Shifts between rate
21 schedules due to rounding of the rate schedules annual consumption limits are
22 shown in Exhibit 3 Schedule 2 Column 6. In addition, an adjustment is made to the
23 number of bills for final billed customers because a customer charge is billed to cus-
tomers who receive a final bill even though they are not included as an active cus-

1 tomer. These customers are not classified as active in the Company's billing sys-
2 tems during the Historic Test Year, so the final bills must be added to active bills to
3 price revenue in this case. Final bill counts are shown in Exhibit 3 Schedule 2 Col-
4 umn 7. Historic Test Year adjusted number of bills in Exhibit 3 Schedule 2 Column
5 8 is the sum of Columns 1 through 7. Bills in Column 8 are used for pricing in Ex-
6 hibit 3 Schedule 1 (pro forma revenue at present rates) and Exhibit 3 Schedule 10
7 (pro forma revenue at proposed rates).

8 Q. Please explain the why Historic Test Year bill counts are adjusted on Exhibit 3
9 Schedule 2 Column 6 described as "Rate Schedule Change".

10 A. As stated in witness Strauss' testimony, Statement No. 15, when Columbia convert-
11 ed customer billing from Mcf usage to therm usage, the commercial and industrial
12 annual consumption usage limits defining rate schedules were converted using a
13 btu conversion factor of 1.073. The shifts of bill counts between rate schedules
14 shown in Column 6 reflect Columbia's efforts to round the annual consumption us-
15 age limits to a higher level than the nearest therm and as a result, a minimum num-
16 ber of test year customers will qualify for a different rate schedule under proposed
17 rates..

18 Q. Please describe the projection of bills for the Future Test Year and Fully Forecasted
19 Rate Year.

20 A. Forecasted active customer counts are first determined on a total company basis by
21 customer class by type of service (sales/Choice transportation/non-Choice trans-
22 portation) by month in the company's forecast model supported by Company wit-
23 ness Efland (Columbia Statement No. 2) on Exhibit 10 Schedule 2. The customer
counts are then spread for each month of the future test year and the fully forecast-

1 ed rate year, based on the historic test year experience, by rate schedule by custom-
2 er class by type of service for Residential and small Commercial sales and Choice
3 customers. The counts for the remaining commercial and industrial customers are
4 the same as in the historic test year. The bills are accumulated based on which rate
5 schedule the customer is on at the end of the Historic Test Year and the results are
6 shown in Exhibit 103 Schedule 2 Column 1.

7 Adjustments resulting from Large Commercial or Industrial customers that are ex-
8 pected to either discontinue or add service during the Future Test Year and Fully
9 Forecasted Rate Year are shown by customer in Exhibit 103 Schedule 4 Pages 7 and
10 21 respectively and summarized in Exhibit 103 Schedule 2 Column 2. New con-
11 struction customers expected to begin service during the Future Test Year and Fully
12 Forecasted Rate Year are shown on Exhibit 103 Schedule 4 Pages 4 and 18 respec-
13 tively, and summarized on Exhibit 103 Schedule 2 Column 3. Customer attrition
14 that is expected to occur during the Future Test Year and Fully Forecasted Rate
15 Year is shown on Exhibit 103 Schedule 4 Pages 3 and 1 respectively and summa-
16 rized on Exhibit 103 Schedule 2 Column 4. The Company considers the Historic
17 Test Year final bill count to be representative of what can be expected during the
18 Future Test Year and Fully Forecasted Rate Year and therefore Historic Test Year
19 final billed count was added to forecasted active bills to price revenue in this case.
20 Final bill counts are shown in Exhibit 103 Schedule 2 Column 5. Future Test Year
21 adjusted number of bills in Exhibit 103 Schedule 2 Column 6 is the sum of Columns
22 1 through 5. Bills in Column 6 are used for pricing in Exhibit 103 Schedule 1 (pro
23 forma revenue at present rates) and Exhibit 103 Schedule 7 (pro forma revenue at
proposed rates).

1 Q. Please explain how Historic Test Year Volumes were converted from Mcf to therms.

2 A. The Company received approval in its last base rate proceeding, Docket No. R-
3 2010-2215623 to modify the Company's billings to Customers from a per Mcf basis
4 to a per therm basis. Current rates were developed using Mcf volumes converted to
5 therm using the btu factor of 1.073. Because the Company's billing history prior to
6 the February 2012 implementation of therm billing is in Mcf, the Company convert-
7 ed historic test year Mcf volumes using the 1.073 btu factor. Volumes and rates are
8 shown in Exhibits 3 and 103 in DTH because the Company's revenue reports are
9 generated in DTH. The Company will continue to bill customers in therms.

10 Q. Please explain the process that was undertaken to produce the DTH used to price
11 Historic Test Year revenue in this case.

12 A. Historic Test Year adjusted DTH shown in Exhibit 3 Schedule 3 Column 7 are the
13 sum of: (a) physical flow DTH in Exhibit 3 Schedule 3 Column 1, (b) adjustment to
14 weather normalized DTH in Exhibit 3 Schedule 3 Column 2, (c) large commercial or
15 industrial adjustments in Exhibit 3 Schedule 3 Column 3, (d) new construction con-
16 sumption in Exhibit 3 Schedule 3 Column 4, (e) attrition consumption in Exhibit 3
17 Schedule 3 Column 5, and (f) rate schedule transfers in Exhibit 3 Schedule 3 Col-
18 umn 6. DTH in Exhibit 3 Schedule 3 Column 7 are used for pricing in Exhibit 3
19 Schedule 1 (pro-forma revenue at current rates) and Exhibit 3 Schedule 10 (pro-
20 forma revenue at proposed rates).

21 Adjustments to consumption resulting from large commercial or industrial custom-
22 ers either discontinuing or adding service during the Historic Test Year are shown
23 by customer in Exhibit 3 Schedule 5 Page 7-9. The DTH are summarized on Exhibit
3 Schedule 5 Page 2 Column 3 and shown in Exhibit 3 Schedule 3 Column 3. DTH

1 calculated for new construction customers beginning service during the Historic
2 Test Year are shown on Exhibit 3 Schedule 5 Pages 4-6. The DTH are summarized
3 on Exhibit 3 Schedule 5 Page 2 Column 1, and shown on Exhibit 3 Schedule 3 Col-
4 umn 4. DTH calculated from customer attrition that occurred during the Historic
5 Test Year are calculated on Exhibit 3 Schedule 5 Page 3 and shown on Exhibit 3
6 Schedule 3 Column 5. Historic Test Year adjusted DTH in Exhibit 3 Schedule 3
7 Column 7 are the sum of Columns 1 through 6. DTH in Column 7 are used for pric-
8 ing in Exhibit 3 Schedule 1 (pro forma revenue at present rates) and Exhibit 3
9 Schedule 10 (pro forma revenue at proposed rates).

10 Q. Please explain the Rate Schedule Change shown in Column 6 of Exhibit 3 Schedule
11 3.

12 A. The DTH shown in Column 6 reflect the shift between the monthly rate blocks for
13 Large General Sales Service ("LGSS") due to rounding of the monthly rate blocks as
14 proposed by witness Strauss in Statement No. 15.

15 Q. Please explain what physical flow DTH in Column 1 of Exhibit 3 Schedule 3 are, and
16 how they relate to volumes included in the Company's financial statements.

17 A. Billed consumption included in the Company's financial statements represent the
18 DTH billed on the customer's monthly invoice based on the customer's billing cycle.
19 Physical flow DTH are recorded in the billing cycle month in which the gas flows.
20 In months where no prior month billing adjustments occur, a customer's physical
21 flow and invoice (actual billed) DTH would be the same.

22 Q. Why is physical flow usage used as a basis for calculating the Company's revenue
23 requirement and developing rate design instead of invoice actual billed usage?

1 A. Usage shown on the customer's invoice and recorded on the Company's books may
2 include adjustments made for prior period billings. Some of these adjustments
3 were made to correct billings originally made during a month that is not included in
4 the Historic Test Year. Adjustments relating to periods that are outside of the His-
5 toric Test Year must be eliminated to reflect representative consumption for deter-
6 mining the Company's revenue requirement and rate design. Physical flow usage is
7 used instead of invoice usage, because it represents only usage flowed during the 12
8 months of the Company's twenty-one billing cycles of the Historic Test Year. The
9 Company captured the monthly consumption by customer that actually was used or
10 flowed by moving all adjusted consumption from the invoice month billing cycle to
11 the month billing cycle for which the adjustment is made. This ensures no out of
12 period adjustments are reflected in the Historic Test Year data, as well as ensuring
the proper monthly blocking of usage during the test year.

14 Q. How were Company witness Efland's total company normalized DTH used in de-
15 termining normalized revenue on Exhibit 3 Schedule 4?

16 A. Once total normalized DTH by month, by class were determined by Company wit-
17 ness Efland, these totals were spread back on a customer-by-customer, month-by-
18 month, basis, based on the customer's actual physical flow consumption and cus-
19 tomer class. Normalized DTH by customer were then accumulated by rate schedule,
20 on a month-to-month basis in a manner identical to how forecasted DTH are de-
21 scribed below starting with the forecast model. The physical flow DTH by rate
22 schedule by rate block from Exhibit 3 Schedule 3 Column 1 are shown in Exhibit 3
23 Schedule 4 Column 1. Column 2 of Exhibit 3 Schedule 4 is where the accumulated
normalized DTH by rate schedule by rate block are recorded. The Weather Normal-

1 ized Adjustment in Exhibit 3 Schedule 4 Column 3 is calculated by subtracting
2 physical flow DTH in Column 1 from the normalized DTH in Column 2. The Weath-
3 er Normalization Adjustment is then recorded in Column 2 of Exhibit 3 Schedule 3.
4 Current base rates are shown in Exhibit 3 Schedule 4 Column 4, and Exhibit 3
5 Schedule 4 Column 5 shows the revenue impact of the Weather Normalization Ad-
6 justment.

7 Q. Please explain the process used to develop Future Test Year and Fully Forecasted
8 Rate Year DTH.

9 A. Forecasted adjusted DTH for both the Future Test Year and the Fully Forecasted
10 Rate Year are shown in Exhibit 103 Schedule 3 Column 7 are the sum of: (a) fore-
11 casted normalized physical flow DTH in Exhibit 103 Schedule 3 Column 1, (b) large
12 commercial or industrial adjustments in Exhibit 103 Schedule 3, Column 3, (c) new
13 construction consumption in Exhibit 103 Schedule 3, Column 4, (d) attrition con-
14 sumption in Exhibit 103 Schedule 3 Column 5, and (e) rate schedule transfers in
15 Exhibit 103 Schedule 3 Column 6. Volumes in Exhibit 103 Schedule 3 Column 7 are
16 used for pricing in Exhibit 103 Schedule 1 (pro-forma revenue at current rates) and
17 Exhibit 103 Schedule 7 (pro-forma revenue at proposed rates) for both the Future
18 Test Year and Fully Forecasted Rate Year.

19 Forecasted DTH are first determined by customer class by type of service
20 (sales/Choice transportation/non-Choice transportation) by month in the compa-
21 ny's forecast model supported by Company witness Efland on Exhibit 10 Schedule
22 2. These DTH are spread for each month of the Future Test Year and Fully Fore-
23 casted Rate Year based on the Historic Test Year by rate schedule by customer class
by type of service for Residential and small Commercial sales and Choice custom-

1 ers. The spread for Large Commercial sales and Choice transportation, all Industri-
2 al customers, and all non-Choice transportation customers is performed down to
3 the individual customer level. The DTH are accumulated based on which rate
4 schedule the customer is on at the end of the Historic Test Year and shown in Col-
5 umn 1 of Exhibit 103 Schedule 3.

6 Adjusted DTH in Exhibit 103 Schedule 3 Column 7 are the sum of Columns 1
7 through 6 for both the Future Test Year and Fully Forecasted Rate Year. DTH in
8 Column 7 are used for pricing in Exhibit 103 Schedule 1 (pro forma revenue at pre-
9 sent rates) and Exhibit 103 Schedule 7 (pro forma revenue at proposed rates).

10 Adjustments resulting from large commercial or industrial customers either discon-
11 tinuing or adding service during the Future Test Year and Fully Forecasted Rate
12 Year are shown by customer in Exhibit 103 Schedule 4 Page 7 and 14 respectively,
13 and summarized in Exhibit 103 Schedule 3 Column 3 for reasons I explained previ-
14 ously with respect to customer bills. Consumption calculated for new construction
15 customers expected to begin service during the Future Test Year are shown on Ex-
16 hibit 103 Schedule 4 Pages 4-6 and Pages 18-21 for the Fully Forecasted Rate Year.
17 The DTH are summarized on Exhibit 103 Schedule 4 Page 2 Column 1 and shown
18 on Exhibit 103 Schedule 3 Column 4. Customer attrition that is expected to occur
19 during the Future Test Year and Fully Forecasted Rate Year is calculated on Exhibit
20 103 Schedule 4 Pages 3 and 17 respectively, and shown on Exhibit 103 Schedule 3
21 Column 5.

22 Q. How were the DTH in both Exhibits 3 and 103 split by rate block?

23 A. A bill frequency was created for each rate schedule for each month of the Historic
24 Test Year, Future Test Year and Fully Forecasted Rate Year at 45 usage levels in-

1 cluding those levels that coincide with the rate blocks of the pertinent rate schedule.
2 For Residential and Small Commercial Sales and Choice transportation customers,
3 the OGIVE method was used to create the bill frequencies. OGIVE is a statistical
4 term for a distribution curve in which the frequencies are cumulative. This method
5 has been used by Columbia since the 1950s and continues to prove to be highly ac-
6 curate to within a minimum of .5% of actual billings. All other rate classes have few
7 enough customers so that the Bill Frequencies were created by accumulating usage
8 on a customer-by-customer, month by month basis.

9 Q. Are there any differences in the methods used to create bill frequencies in this filing
10 and that presented in Columbia's last general rate case?

11 A. Yes. LGSS bill frequencies were calculated on a customer by customer basis instead
12 of using OGIVE as in the last case, to improve the accuracy of the less predictable
13 LGSS class.

14 Q. Please explain Schedules 6 through 9 of Exhibit 3.

15 A. Schedules 6 and 7 eliminate certain per book amounts (off system sales revenues,
16 unbilled revenues and unbilled gas costs) that are not relevant to a pro forma calcu-
17 lation of revenues and expenses. Schedules 8 and 9 show the calculated split of per
18 books gas cost, Storage Interest Component, Rider USP and Unbundled Uncollecti-
19 bles by customer class used in reconciling per books revenue to annualized revenue
20 revenue in Exhibit 3 Page 9.

21 Q. How was pro forma revenue at present rates calculated?

22 A. As shown in both Exhibit 3 and 103 Schedule 1, adjusted test year bills from Sched-
23 2 are shown in Column 1 and adjusted test year DTH from Schedule 3 are shown
in Column 2. Present rates are shown in Column 3. Revenue is calculated in Col-

1 umn 4 by multiplying the customer charge by number of bills and volumetric rates
2 by volumes. An average rate per DTH is calculated in Column 5 by dividing Column
3 4 by Column 2. Pro forma revenue at present rates was calculated using the PGC
4 rate, Rider USP rate and State Tax Adjustment Surcharge ("STAS") in effect as of
5 April 1, 2012, the most recent available at the time the schedules were developed
6 with the exception of the Unbundled Uncollectibles rate (please refer to Attachment
7 MJB-1, attached to this testimony).

8 Q. Please explain the DTH and Revenue Summary at Current Rates on Exhibit 3 Page
9 9 and 103 Page 16.

10 A. These pages summarize the adjustments that I have explained previously.

11 Q. Please explain the adjustment to Forfeited Discounts in Exhibit 3 Page 9 and Exhib-
12 it 103, Pages 12 and 16.

13 A. Attachment MJB-2 compares Account 487 revenue to total billed revenue for the
14 three most recent 12 month periods including the historic test year and calculates a
15 three year average. The average of the last three years was selected to match the
16 same basis used by the Company and approved by the Commission in the Compa-
17 ny's most recent rate case to determine an average net write-off rate used for annu-
18 alization of uncollectible expense. As with net write-offs, Forfeited Discounts his-
19 torically produce a reasonably predictable percentage of billed revenue over time. A
20 three year average is used to account for the percentage differences caused primari-
21 ly by changes in gas cost recovery revenue.

22 The historic three year average percentage of billed revenue is applied to annualized
23 Historic Test Year revenue resulting in annualized historic test year Forfeited Dis-
counts shown on Attachment MJB-2, page 1. The historic three year average per-

1 centage of billed revenue is applied to annualized forecasted test year revenue re-
2 sulting in forecasted test year annualized Forfeited Discounts shown on Attachment
3 MJB-2, page 2. The historic three year average percentage of billed revenue is ap-
4 plied to annualized rate year revenue resulting in rate year annualized Forfeited
5 Discounts shown on Attachment MJB-2, page 3.

6 Q. Please explain Exhibit 3 Schedule 10 and Exhibit 103 Schedule 7.

7 A. These Schedules calculate pro forma revenues at proposed rates for the Historic
8 Test Year, Future Test Year and Fully Forecasted Rate Year, respectively, reflecting
9 the rate design prepared by Company witness Strauss, as shown on Exhibit 103
10 Schedule 8.

11 Q. Please explain Page 10 of Exhibit 3 and Pages 13 and 17 of Exhibit 103.

12 A. These pages summarize annualized total revenue at present rates as calculated on
13 Exhibit 3 Schedule 10 and Exhibit 103 Schedule 7. Exhibit 103 includes annualized
14 total revenue for both the Future Test Year and Fully Forecasted Rate Year. Col-
15 umn 1 shows pro forma Delivery Service revenue at present rates. Column 1 is car-
16 ried forward from Page 9, Column 10 in Exhibit 3 and Pages 12 and 14, Column 10
17 in Exhibit 103. Column 2 shows a summary of gas costs at present rates in effect as
18 of April 1, 2012. Column 3 shows a summary of Rider USP at present rates in effect
19 as of April 1, 2012. Column 5 shows a summary of Unbundled Uncollectibles. De-
20 tailed calculations by rate schedule for Columns 2, 3, 4 and 5 are shown in Schedule
21 1. Column 6 shows total revenue at present rates used for deriving the revenue re-
22 quirement and designing rates.

23 Q. Please explain Pages 6 - 8 of Exhibit 3 and Pages 6-11 of Exhibit 103.

1 A. The summary shows by rate schedule by customer class pro forma test year bills
2 (Column 1), Consumption (DTH) (Column 2), Revenue at Present Rates (Column
3 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5).

4 The summary serves as a comparison of revenue at present and proposed rates.

5 Q. Please summarize the drivers that make up the difference in revenue in Exhibit 103
6 between the Future Test Year and the Fully Forecasted Rate Year.

7 A. The difference between the revenue in the Future Test Year and the Fully Forecast-
8 ed Rate year is driven by changes in customer growth, attrition, declining use per
9 customer, and expected changes in customer counts, and usage for large customers
10 based upon a customer by customer review. Ms. Efland is responsible for explain-
11 ing those drivers that are reflected in here forecast model.

12 Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Calculation of Unbundled Uncollectible Rate Utilized in Exhibit No. 3 and Exhibit No. 103
Calculated Using Gas Costs as of April 1, 2012

Line No.	Description	Reference	Rate \$
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 5, Line 5 (4/01/12 Quarterly GCR Filing)	3.8940
2	Off System Sales & Capacity Release Credit	Exhibit 1-A, Schedule 1, Page 1, Col. 5, Line 6 (4/01/12 Quarterly GCR Filing)	(0.1465)
3	Choice Credit	Exhibit 1-A, Schedule 3, Page 1, Line 17c (4/01/12 Quarterly GCR Filing)	0.2986
4	Total Commodity Cost of Gas		4.0461
5	Uncollectible Experience Ratio	Exhibit No. 4, Schedule No. 2, Page 12, Line 10 - (3 Year Average) - %	0.0146
6	Total Unbundled Uncollectible Rate	(Line 4 x Line 5)	0.0590

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending May 31, 2012

Attachment MJB-2
Page 1 of 3
Witness: M. J. Bell

Line No.	12 Mos <u>May 2010</u>	12 Mos <u>May 2011</u>	12 Mos <u>May 2012</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,040,582	\$ 1,200,505	\$ 929,702	\$ 3,170,789
2 Per Books Billed Revenue	<u>\$ 397,688,616</u>	<u>\$ 521,827,918</u>	<u>\$ 349,170,640</u>	<u>\$ 1,268,687,174</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2617%	0.2301%	0.2663%	0.2499%
4 Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 7)				\$ 280,642,918
5 Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 10)				\$ 93,111,960
6 Total Sales and Transportation Revenue (Line 5 + Line 6)				<u>\$ 373,754,878</u>
7 3 Year Average				0.2499%
8 Annualized Forfeited Discounts (Line 7 * Line 6)				<u>\$ 934,013</u>
9 Historic Test Year Acct 487 (Ex. 3, Page 9)				\$ 929,702
10 Annualization Adjustment (Line 8 - Line 9)				<u><u>\$ 4,311</u></u>

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending May 31, 2013

Attachment MJB-2
Page 2 of 3
Witness: M. J. Bell

Line No.	12 Mos <u>May 2010</u>	12 Mos <u>May 2011</u>	12 Mos <u>May 2012</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,040,582	\$ 1,200,505	\$ 929,702	\$ 3,170,789
2 Per Books Billed Revenue	<u>\$ 397,688,616</u>	<u>\$ 521,827,918</u>	<u>\$ 349,170,640</u>	<u>\$ 1,268,687,174</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2617%	0.2301%	0.2663%	0.2499%
4 Future Test Year Sales Revenue (Ex. 103, Page 10, Line 7)				\$ 287,456,573
5 Future Test Year Transportation Revenue (Ex. 103, Page 10, Line 10)				\$ 89,483,287
6 Total Sales and Transportation Revenue (Line 4 + Line 5)				<u>\$ 376,939,860</u>
7 3 Year Average				0.2499%
8 Annualized Forfeited Discounts (Line 4 * Line 6)				<u>\$ 941,973</u>
9 Future Test Year Acct 487 (Ex. 3, Page 9)				\$ 934,013
10 Annualization Adjustment (Line 7 - Line 8)				<u><u>\$ 7,960</u></u>

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending June 30, 2014

Attachment MJB-2
Page 3 of 3
Witness: M. J. Bell

Line No.	12 Mos <u>May 2010</u>	12 Mos <u>May 2011</u>	12 Mos <u>May 2012</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,040,582	\$ 1,200,505	\$ 929,702	\$ 3,170,789
2 Per Books Billed Revenue	<u>\$ 397,688,616</u>	<u>\$ 521,827,918</u>	<u>\$ 349,170,640</u>	<u>\$ 1,268,687,174</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2617%	0.2301%	0.2663%	0.2499%
4 Fully Forecasted Rate Year Sales Revenue (Ex. 103, Page 12, Line 7)				\$ 287,666,266
5 Fully Forecasted Rate Year Transportation Revenue (Ex. 103, Page 12, Line 10)				\$ 90,231,823
6 Total Sales and Transportation Revenue (Line 5 + Line 6)				<u>\$ 377,898,089</u>
7 3 Year Average				0.2499%
8 Annualized Forfeited Discounts (Line 7 * Line 6)				<u>\$ 944,367</u>
9 Fully Forecasted Rate Year Acct 487 (Ex. 3, Page 11)				\$ 941,973
10 Annualization Adjustment (Line 8, - Line 9)				<u><u>\$ 2,394</u></u>

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

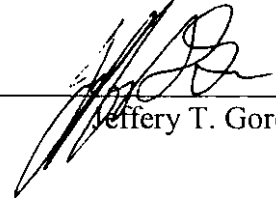
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Jeffery T. Gore, being Manager of Regulatory Strategy and Support of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 4 and 104-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. JTG-R1 (Confidential) and JTG-R2, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Jeffery T. Gore

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SEPTEMBER 28, 2012

Columbia Gas of Pennsylvania, Inc.

Direct Testimony of Jeffery T. Gore

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1 Q. Please state your name and business address.

2 A. My name is Jeffery T. Gore and my business address is 200 Civic Center Drive,
3 Columbus, OH 43215.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by NiSource Corporate Services Company ("NCSC"). I assumed my
6 current position as Manager of Regulatory Strategy and Support in June 2010.

7 Q. What are your responsibilities as Manager?

8 A. As Manager, my principal responsibilities include providing support in regulatory
9 compliance filings and base rate case support as requested by the NiSource Inc.
10 ("NiSource") natural gas distribution segment.

11 Q. Please describe your educational background and professional experience.

12 A. In 1985, I graduated from The Ohio State University with a Bachelor of Science in
13 Business Administration degree, double majoring in Accounting and Computer
14 Science. I have a non-practicing Certified Public Accounting license.
15 I have 20 years experience working in general accounting for many of the natural
16 gas local distribution companies making up the NiSource natural gas distribution
17 segment. My most recent responsibility prior to my current position was as a
18 Manager General Accounting with responsibility for overseeing and managing the
19 financial books of account for Bay State Gas Company, now d/b/a Columbia Gas
20 of Massachusetts.

21

1 Q. Have you previously testified before this or other utility Commissions?

2 A. Yes, I testified before the Massachusetts Department of Public Utilities on behalf
3 of Bay State Gas Company d/b/a Columbia Gas of Massachusetts and submitted
4 direct testimony before the Kentucky Public Service Commission on behalf of
5 Columbia Gas of Kentucky, Inc. I previously submitted direct written testimony
6 regarding the revenue requirement and cost of service in the Company's last rate
7 case at Docket No. 2010-2215623.

8 **Statement of Purpose**

9 Q. Please describe the purpose of your testimony in this proceeding.

10 A. The purpose of my testimony is to present Columbia's cost of service and to
11 quantify an existing revenue deficiency based on 2012 operating costs and
12 revenues, as adjusted. As part of the cost of service analysis, my testimony
13 supports Columbia's Cost of Service Operating and Maintenance ("O&M")
14 expenses.

15 Q. Would you please provide a listing of the exhibits that you are sponsoring
16 through your testimony?

17 A. Yes. I am supporting the following exhibits either in full or in part for the historic
18 and rate years, respectively: Exhibit 1 and 101; Exhibit 2 and 102; Exhibit 4 and
19 104; ; Exhibit 12; Exhibit 13 and 113; Exhibit 408 and Exhibit 414. All of these
20 exhibits were either prepared by me or under my direct supervision and control.

21 Q. What test years will you be addressing in this testimony?

1 A. I will be addressing the twelve-month period ending May 31, 2012 as the "historic
2 test year", the twelve-month period ending May 31, 2013 as the "future test year"
3 and the twelve-month period ending June 30, 2014 as the "fully forecasted rate
4 year".

5 Q. What is the basis for Columbia's claim for revenue deficiency?

6 A. Columbia's revenue deficiency is calculated utilizing a rate year ending June 30,
7 2014 for rate base, revenues and expenses, with pro-forma adjustments for known
8 and measurable changes. Consistent with Act 11, this approach recognizes that a
9 utility's revenues should be sufficient to recover the reasonably and prudently
10 incurred costs of providing safe and reliable service to its customers including a fair
11 rate of return on the used and useful investment that the utility has devoted to such
12 service.

13 **Cost of Service/Revenue Deficiency**

14 Q. Would you please summarize the results of the cost of service requirement and
15 resulting revenue deficiency?

16 A. As indicated on Exhibit 102, Schedule 3, Page 5, Columbia has a revenue
17 deficiency of \$77,311,053 based upon pro forma revenue requirement for the
18 twelve months ending June 30, 2014. Columbia's computation of the revenue
19 deficiency reflects total rate base of \$1,011,680,660. In addition, the
20 computation of the revenue deficiency reflects known and measurable changes to
21 both utility operating income and rate base, which are explained later in my

1 testimony and in the testimony of other Company witnesses.

2 Q. Will you please describe Exhibit 2, Schedule 3, Page 3?

3 A. This Exhibit is the statement of operating income, pro forma at present and
4 proposed rates, for the historic test year. Column 2 reflects the per book
5 operating revenue, operating revenue deductions, income taxes and utility
6 operating income for the Company for the twelve months ended May 31, 2012.
7 These amounts have been adjusted to reflect pro forma operating income at
8 historic test year present rates in Column 4. Column 5 provides the adjustments
9 necessary to annualize the effects of the proposed rate increase. Column 3
10 adjustments are referenced in Column 1. Column 5 adjustments are detailed in
11 Exhibit 2, Schedule 3, Page 6. Column 6 shows the resulting pro forma operating
12 revenue, expenses and income for the historic test year at proposed rates.

13 Q. Please continue with Exhibit 2, Schedule 3, Pages 4 through 6.

14 A. Page 4 shows pro forma interest expense of \$21,048,713 calculated by
15 multiplying the Rate Base shown on Exhibit 8 by the weighted cost of short and
16 long term debt shown on Exhibit 400.

17 Exhibit 2, Schedule 3, Page 5 calculates the historic test year revenue deficiency to
18 be \$14,496,734. This deficiency is calculated by multiplying the net operating
19 income deficiency of \$8,357,869 by the Revenue Conversion Factor. The
20 development of the Revenue Conversion Factor, to gross up for state and federal
21 income taxes and uncollectible expenses, is shown on lines 8-16.

1 Page 6 shows the calculated adjustments to pro forma expenses and income taxes
2 to achieve the requested return on Rate Base of 8.52% shown on Exhibit 400
3 using the historic test year data.

4 Q. Is Exhibit 102 presented in the same format as Exhibit 2?

5 A. Yes. Exhibit 102, Schedule 3 is a Statement of Income based on historic test year,
6 future test year, fully forecasted rate year and Proposed Rates for the fully
7 forecasted rate year. Exhibit 102, Schedule 3, Page 3 begins with the historic test
8 year at present rates in Column 2 that was calculated in Exhibit 2, Schedule 3,
9 Page 3, Column 4. Adjustments in Column 3 are then made to determine pro
10 forma future test year at present rates in Column 4. Adjustments in Column 5 are
11 then made to determine the fully forecasted rate year at present rates in Column
12 6. Column 7 shows the revenue requirement of \$77,311,053 necessary to achieve
13 a fair rate of return. The various exhibits in support of the adjustments at present
14 and proposed rates are identified in Column 1. Column 8 shows the resulting
15 calculated pro forma operating revenues, expenses and income for the fully
16 forecasted rate year at the proposed return on Rate Base.

17 Q. Please explain Exhibit 102, Schedule 3, Page 4.

18 A. This page calculates synchronized interest expense based upon the future test
19 year rate base multiplied by the weighted cost of debt in Lines 1 thru 4 and
20 similarly based on the fully forecasted rate year rate base multiplied by the
21 weighted cost of debt in Lines 5 thru 8.

1 Q. Please explain Page 5 of Exhibit 102, Schedule 3.

2 A. This page presents the calculation of the required revenue increase of \$77,311,053
3 based upon the future test year net income deficiency of \$44,572,509. Also
4 reflected on this schedule is the additional normal uncollectible expense of
5 \$1,127,195 generated by Columbia's requested increase in revenues as calculated
6 on page 6 of the Exhibit 102.

7 The revenue gross up factor is very similar to the factor developed in Exhibit 2,
8 Schedule 3, Page 5 explained previously. The effective State Income Tax rate has
9 been recalculated and reflects differences in the tax net operating loss positions.

10 **Operation & Maintenance Expenses**

11 Q. What is Columbia's per books test year O&M Expenses?

12 A. In the historic test year, Columbia recorded \$126,145,237 in O&M expense
13 exclusive of gas cost, as shown on Exhibit 4, Schedule 1, Page 2, Column 1.

14 Q. Was this historic test year O&M expense level used in the development of
15 Columbia's proposed expense level for this filing?

16 A. Yes. The historic test year level of O&M expense was first normalized and
17 annualized with the result being used as a basis for pro forma adjustments to
18 develop the future test year expenses. Exhibit 4, Column 2 reflects the elimination
19 of \$556,380 in costs related to the prior rate case that were incurred during the
20 historic test year. The normalization of the rate case expenses for this case is
21 explained later in my testimony. Column 3 reflects elimination of start-up costs of

1 \$152,706 for the development of the new NiSource accounting system project
2 known as NiFit, the costs of which Columbia proposes to amortize and which will
3 be discussed later in this testimony. Further explanation of each O&M adjustment
4 for both the historic test year, the pro-forma future test year and the pro forma fully
5 forecasted rate year are provided later in this testimony and on Exhibits 4 and 104.

6 Q. What types of adjustments are you proposing to O&M expense?

7 A. In addition to the elimination of the prior rate case and NiFit costs, I am
8 proposing the following adjustments to O&M expense:

- 9 1) Labor related adjustments for incentive compensation, merit increases,
10 increased employees and transfers to capital and other affiliated companies;
- 11 2) Removal of lobbying expenses;
- 12 3) Annualized benefit expense;
- 13 4) NiSource Corporate Services costs as supported by Witness Cogar, Columbia
14 Statement No. 13;
- 15 5) Corporate insurance;
- 16 6) Inflation;
- 17 7) Advertising;
- 18 8) Normalization for rate case expense;
- 19 9) NiFit Cost Amortization;
- 20 10) DIMP costs as supported by Witness Kitchell, Columbia Statement No. 7.
- 21 11) Uncollectibles expense; and

12) Other miscellaneous items.

Q. Please describe how your testimony is presented.

A. Page 2 of Exhibits 4 and 104 summarize, by cost driver, adjustments for the historic test year, future test year and fully forecasted rate year, respectively. My testimony is organized to explain the adjustment to each cost driver in the order in which they are presented on Exhibits 4 and 104.

Labor

Exhibit 4: Schedule 1 Line 1; Schedule 2 Pages 3, 4 and 5.

Exhibit 104: Schedule 1 Line 1; Schedule 2 Pages 1, 2 and 3

Q. Please provide a brief explanation of the labor adjustments.

A. Labor costs in the historic test year were adjusted to reflect the annualized employee and associated wage levels as of May 2012. An adjustment of \$2,765,720 is being made to the historic test year labor expense level of \$22,569,598 to develop the total historic test year labor expense level of \$25,335,318 as shown on Exhibit 4.

The labor adjustment consists of three items;

(1) the gross annual wage level of Columbia's 510 active employees as of May 2012 was compared to the per book straight time wages. This adjustment annualizes the straight time wages based on the employees and wage rates as of May 31, 2012. The difference, or annualization adjustment, was further adjusted for an updated labor capitalization ratio as provided on Exhibit No. 4, Schedule 2,

1 Page 7 of 27. This capitalization rate is based on a 5 year average of labor
2 capitalization rates,

3 (2) removal of \$30,000 of severance expense recorded in the historic test
4 year,

5 (3) an adjustment to the historic test year labor O&M to reflect the 5 year
6 average capitalization rate calculated on Exhibit No. 4, Schedule 2, Page 7, Lines
7 10 thru 14. This adjustment resets the historic test year O&M level to the new
8 capitalization rate, while adjustment 1 only impacts the annualization adjustment
9 portion of the labor claim.

10 Q: Why did the Company use a 5 year capitalization average instead of the ratio
11 experienced in the historic test period?

12 A: Company witness Kitchell (Columbia Statement No. 7) explains in his testimony
13 why the historic test year capitalization percentage is not reflective of normal
14 operating activity, in particular because Columbia will be reducing the amount of
15 capital projects that will be undertaken by Columbia employees and instead focus
16 their expertise on O&M matters. As a result, the Company is proposing to use a
17 capitalization rate based on the 5 most recent calendar years. This provides a
18 reasonable estimate of the expected future capitalization rate.

19 Q: Please describe the development of the Company's claim for future test year labor
20 expense, exclusive of incentive compensation and new employees.

21 A: The pro forma historic test year expense level of \$25,335,318 is used as the basis

1 for the future test year adjustments. This amount is already net of transfers to
2 capital. The annual future test year wage levels as of May 2013 were developed
3 using the current employee levels as of May 2012. A merit or base pay increase is
4 reflected in the future test year adjustment as detailed on Exhibit 104, Schedule
5 No. 2, Page 1. The resulting future test year labor expense, exclusive of incentive
6 compensation and new employees, as claimed in this case is \$26,090,462, as
7 shown on Exhibit 104, Schedule 1, or \$755,144 above the annualized historic test
8 year level.

9 Q. Please provide a more detailed explanation of the future test year adjustment for
10 cost increases related to merits.

11 A. A merit adjustment was not necessary for the historic test year since the annual
12 wages as of May 31, 2012 (end of historic test period) were used to develop the
13 historic test year labor expense. The future test year reflects an adjustment for
14 the annual merit increases that will be applied prior to May 31, 2013. Two
15 increases will be applied in the future test year for clerical, exempt and non-union
16 employees. The first increase occurred in June 2012. The second increase will
17 occur in March 2013 as Columbia is adjusting the timing of the normal annual
18 pay increase from June to March. This change reflects management's decision to
19 align the pay increase more closely with the annual performance review
20 discussions held at the end of each calendar year. The timing of the merit
21 increases and the percentages used were based on information provided by

1 Columbia's Human Resources - Compensation department. Additionally, the
2 future test year includes increases for union employees based on contract terms
3 or renewal dates. Please refer to Exhibit No. 104, Schedule 2, Page 2.

4 Q. Please describe the development of the Company's claim for fully forecasted rate
5 year labor expense.

6 A. The future test year expense level of \$26,090,462 is used as the basis for the fully
7 forecasted rate year adjustments. Merit or base pay increases planned for this
8 period are provided on Exhibit No. 104, Schedule 2, Page 3. The annualized
9 future test year labor was adjusted by a gross merit increase of \$856,891 to
10 determine the annualized fully forecasted test year labor level as used as a claim
11 in this rate case. The O&M expense portion of the increase is \$578,144.

12 In addition, Exhibit No. 104, Schedule 2, Page 3, Lines 5 thru 20 calculates the
13 estimated expected impact to rate year expense of the annualized labor
14 adjustment.

15 Incentive Compensation

16 **Exhibit 4:** Schedule 1 Line 2; Schedule 2, Page 6

17 **Exhibit 104:** Schedule 1 Line 2; Schedule 2 Pages 4 through 9

18 Q. Please provide an explanation of the historic test year incentive adjustment.

19 A. Columbia's historic test year per books incentive level of \$1,633,221 was
20 decreased by \$25,739 to reflect the actual level of expense. This adjustment
21 removes any out of period true-ups for the prior year and adjusts the accrual

1 made in the test year to the experienced pay out level at the claimed capitalization
2 percentage. Detail supporting the historic test year adjustment of is provided on
3 Exhibit 4, Schedule 2, Page 6.

4 Q. Please explain the calculation of the future test year incentive compensation
5 adjustment.

6 A. The future test year expense is adjusted to reflect the planned annualized 2013
7 incentive gross payout at the target level (see description of plan for target level
8 definition in Exhibit No. 104, Schedule No. 2; Pages 5 thru 9). The incentive plan
9 is established on the premise that over time, the company expects to pay
10 incentives at target levels. Supporting information for the future test year target
11 level was provided by Human Resources for development of the incentive level
12 used in this rate case. Exhibit 104, Schedule 2, Page 4 sets forth the company's
13 claim for the future test year incentive compensation. The future test year
14 adjustment of \$265,937 reflects a reduction in incentive compensation expense as
15 the historic test year incentive was paid at higher than target levels.

16 Q. Would you please outline the individual goal setting aspect of the incentive
17 compensation process?

18 A. Yes. Incentives are dependent, in part, upon each exempt employee's individual
19 performance. Individual performance goals are established in the first quarter of
20 each year for each employee. The goals and objectives for the corporation, as
21 initiated by the CEO, are cascaded throughout the organization. As this cascading

1 occurs, each leader can add additional details to create the appropriate linkage
2 between the overall corporate goals and the employee's responsibilities. The
3 result of the cascading process is the creation of a Performance Management
4 Worksheet ("PMW") for each employee. The goals within a PMW fall within one
5 of four categories: people, perception, performance and profit. The incentive
6 plan does not provide for a payout if NiSource does not meet incentive plan
7 targets for the year.

8 Q. Please explain the calculation of the fully forecasted rate year incentive
9 compensation adjustment.

10 A. The fully forecasted rate year expense is adjusted to reflect the annualized 2014
11 target level payout as provided by the Human Resource Department for this case.

12 The increased expense of \$40,177 is provided on Exhibit No. 104, Schedule No. 2,
13 Page 4, Lines 6 - 10.

14 Additionally, on Lines 11 thru 24, the expected rate year expense impact of the
15 incentive adjustment is provided.

16 **Labor – New Employees after Historic Test Year**

17 ***Exhibit 4: Schedule 1 Line 3***

18 ***Exhibit 104: Schedule 1 Line 3; Schedule 2 Page 10***

19 Q. Please provide an explanation for the new employees.

20 A. Columbia's will be adding 55 new employees prior to December 2012. Please
21 refer to witness Kitchell's testimony for an explanation of the need to add these

new employees.

Q. Please provide an explanation for the calculation of new employee labor costs.

A. Exhibit No. 104, Schedule 2, Page 10 details the various positions, expected wages, base increase and percentage of time allocated to operation and maintenance expense. The expense impact for the future test year is \$1,272,250 as provided in Column H.

Q. Please provide an explanation for the fully forecasted rate year new employee labor costs.

A. Continuing on Page 10, Column I provides the incremental annualized O&M costs related to the new employees totaling \$27,368. This adjustment relates to merit increases that will be provided to these new employees during the fully forecasted rate year.

Additionally, Lines 12 thru 25 provide an estimate of the expected rate year cost adjustment that will be incurred for these annualized expenses.

Pension Expense

Exhibit 4: Schedule 1 Line 4

Exhibit 104: Schedule 1 Line 4

Q. What is the basis for the Company's qualified Pension claim?

A. The Company's claim for the qualified pension expense is based on Pension Contributions made by the Company to the Pension trust. Specifically, the gross claim is based on a three year average of the gross Pension contributions. These

gross amounts are then adjusted to expense based on the capitalization rate.

Q. Why did the Company use 3 years in this calculation?

A. Pension contributions can vary greatly between years based on a variety of factors including legal funding requirements, business needs, the impact of trust fund investment performance, and discount rates. Given the desire to set Columbia's rate at levels to recover an on-going expense level, the use of multi-year average contribution levels is appropriate. For example, the qualified Pension contributions in the historic test year were \$15,020,000 and included a December 2011 contribution of \$13,092,000. The large December contribution was made to early fund planned 2012 and 2013 Pension contributions.

Therefore, a 3 year contribution level is a reasonable method for calculating the qualified pension expense in this case.

Q. Please provide an explanation of the historic test year qualified pension adjustment.

A. Columbia's test year expense reflects qualified pension activity for the twelve ended May 31, 2012, including contributions and capitalization as recorded. These amounts are reflected in Exhibit No. 104, Schedule No. 2, Page 11, Columns 1 thru 3.

Q. Please explain the calculation of the future test year qualified pension adjustment.

A. Columbia's future test year expense was adjusted to reflect the average annual

1 contributions using a 3 year average ending May 31, 2013 – Exhibit No. 104,
2 Schedule No. 2, Page 11, Column 4, Line 1. Further Column 5 calculates the
3 portion charged to capital and Column 6 provides the \$6,730,583 of qualified
4 pension expense for the normalized future test period. Included in the 3 year
5 average are projected pension contributions as provided by AON Hewitt.

6 Q. Please explain the calculation of the fully forecasted rate year qualified pension
7 adjustment.

8 A. Columbia's fully forecasted rate year expense was adjusted to reflect the average
9 annual contributions using a 3 year average ending June 30, 2014 – Exhibit No.
10 104, Schedule No. 2, Page 12, Column 2, Line 1. Further Column 3 calculates the
11 portion charged to capital and Column 4 provides the \$3,743,348 of qualified
12 pension expense for the fully forecasted rate year. Included in the 3 year average
13 are projected 2014 pension contributions as provided by AON Hewitt.

14 Q. How did the Company calculate the Supplemental Executive Retirement Income
15 Plan ("SERP") in this claim?

16 A. The SERP claim is based on estimated expense as provided by AON Hewitt
17 (Columbia's pension actuary). The future test year reflects the annualized gross
18 expense for 2013 (see Exhibit No. 104, Schedule No. 2, Page 11, Line 2) and the
19 fully forecasted rate year reflects the annualized gross expense for 2014 (see
20 Exhibit No. 104, Schedule No. 2, Page 12). Each gross expense amount was
21 adjusted for the capitalization impact to reflect expense levels.

1 Additionally, in Exhibit No. 104, Schedule 2, Page 12, Lines 26 thru 38 the
2 expected rate year impact of this annualized adjustment (as well as the other
3 benefit costs) is provided.

4 **OPEB – Other Post Employment Benefits**

5 ***Exhibit 4: Schedule 1 Line 5***

6 ***Exhibit 104: Schedule 1 Line 5; Schedule 2, Page 11***

7 Q. Please describe the various items under the term OPEB costs.

8 A. There are four items relating to post employment benefits; (1) ongoing medical
9 and life insurance accruals based on actuarial studies provided by AON Hewitt,
10 (2) amortization of the transition obligation developed in the early 1990's relating
11 to the adoption of OPEB accrual accounting rules, (3) SFAS 112 benefit cost
12 accrual and amortization expense and (4) the impact of the deferred accounting
13 relating to differences between established recovery of costs and actual costs.

14 Q. Please describe the various adjustments made to the ongoing medical and life
15 insurance OPEB expenses in Exhibit 104, Schedule 2, Page 11, Lines 4 - 5.

16 A. The future test year on-going OPEB expenses have been adjusted to reflect a zero
17 cost claim. Company witness Schmelzer (Columbia Statement No. 14) details the
18 Company's position regarding why the zero claim is appropriate. The fully
19 forecasted rate year claim is also zero.

20 Q. Please describe the various adjustments made to the transition obligation
21 amortization in Exhibit 104, Schedule 2, Page 11, Line 6.

A. The amortization for this item will be completed on December 31, 2012. Therefore, the future test year and fully forecasted rate year claim is zero for this item.

Q. Please describe the various adjustments made to the SFAS 112 cost in Exhibit 104, Schedule 2, Page 11, Line 8.

A. The SFAS 112 future test year claim includes two types of SFAS 112 expenses: (1) amortization of a regulatory asset. The \$83,376 annual amortization continues throughout the future test year and fully forecasted rate year; and (2) on-going annual costs. The future test year claim of \$55,448 for this item reflects a five year average of on-going costs as follows:

Twelve Months Ended	On-going SFAS 112
May 2008	(\$64,887)
May 2009	(\$305,142)
May 2010	\$217,328
May 2011	\$945,949
May 2012	<u>(\$516,008)</u>
Total	\$277,240
5 Year Average	\$55,448

As noted in the table, the on-going costs are volatile with some years having positive and some having negative expense. The proposed 5 year average provides for a reasonable expected level of costs for ratemaking.

Q. Please describe the various adjustments made to the OPEB deferrals in Exhibit 104, Schedule 2, Page 11, Lines 9 and 10.

A. Line 9 reflects the deferral of the difference between historic test year expense and amounts recovered in rates. This amount is removed from the future test year and fully forecasted rate year with the amounts included in Line 10. Line 10 reflects a 2 year pass back of the expected remaining over collection position expected as of June 30, 2013. Witness Schmelzer supports the calculation of this pass back detailed in Exhibit No. 104, Schedule 2, Pages 13 and 14.

Benefits - Other Employee Benefits

Exhibit 4: Schedule 1 Line 6

Exhibit 104: Schedule 1 Line 6; Schedule 2, Page 12, Lines 12 - 20

Q. Were Other Employee Benefits adjusted in the future test year?

A. Yes, as shown on Exhibit 104, Schedule 1, Page 2, Line 5, a net increase of \$706,495 is included in Columbia's future test year. The various benefits on Exhibit 104, Schedule 2, Page 11, Lines 12 through 20 have been adjusted to the most current estimates provided by AON Hewitt for annualized gross costs for 2013. The benefits included in Line 19 relate to billings from affiliates and no adjustment was made to the historic test year amount. Lines 12 through 20 were further adjusted for capitalized amounts and incremental employees.

Q. Were Other Employee Benefits adjusted in the fully forecasted rate year?

A. Yes, as shown on Exhibit 104, Schedule 1, Page 2, Line 6, a net increase of

1 \$335,734 is included in Columbia's fully forecasted rate year expense. The various
2 benefits on Exhibit 104, Schedule 2, Page 12, Lines 12 through 20 have been
3 adjusted to the most current estimates provided by AON Hewitt for annualized
4 gross costs for 2014. The benefits included in Line 19 relate to billings from
5 affiliates and no adjustment was made to the historic test year amount. Lines 12
6 through 20 were further adjusted for capitalized amounts and incremental
7 employees.

8 Additionally, on this page in lines 26 thru 38, the expected rate year expense
9 impact of these annualized other benefit costs as well as pension costs are
10 provided.

11 Outside Services

12 **Exhibit 4:** Schedule 1 Line 7

13 **Exhibit 104:** Schedule 1 Line 7

14 Q. Were outside service expenses adjusted for reasons other than inflation?

15 A. Yes. The per books amount in Exhibit 4 was adjusted by \$542,740 to reflect the
16 elimination of prior rate case expense mentioned previously in my testimony.

17 Rents and Leases

18 **Exhibit 4:** Schedule 1 Line 8; Schedule 2 Page 8

19 **Exhibit 104:** Schedule 1 Line 8; Schedule 2 Page 15

20 Q. How were rents and leases adjusted for the historic test year?

21 A. Rents and leases were first separated into; a) rents and leases related to buildings

1 and b) other rents and leases including communications equipment and lines,
2 office machines and furnishings. Rents and leases attributable to contractual
3 levels for buildings were annualized on Exhibit 4, Schedule 2, Page 8 for a total of
4 \$550,080. This amount was then reconciled with the per book test year level of
5 \$644,828. During the historic test year some building rental agreements were
6 not renewed, causing the historic test year to be higher than the normalized test
7 year by \$94,748 as noted on Exhibit 4, Schedule 4, Page 8, Line 21. The
8 remaining portion of rents and leases includes communications equipment and
9 lines, office machines, and other items. The historic test year level related to
10 these is \$753,250 and remains unchanged.

11 Q. Please explain the adjustment to rents and leases for the future test year.

12 A. Known changes to building leases were included on Exhibit 104, Schedule 2, Page
13 15 resulting in an increase of \$374,221 for the future test year claim. As noted in
14 Witness Kitchell's testimony, the Company has begun leasing a facility at Alpine
15 Point and discontinued leasing buildings in Bethel Park and Neville Island. The
16 net impact of this change is an increase of \$350,000 to rents expense after
17 considering the addition of the Alpine Point facility and the discontinued leases
18 for the Bethel Park and Neville Island facilities. The remaining portion of the
19 increased rent expense primarily reflects the Company's expansion in the
20 headquarters facility in Canonsburg due to the need for more office space for
21 increasing employee levels. No further adjustments are proposed or anticipated

1 for the fully forecasted rate year.

2 **Corporate Insurance**

3 ***Exhibit 4:*** *Schedule 1 Line 9; Schedule 2 Page 9*

4 ***Exhibit 104:*** *Schedule 1 Line 9; Schedule 2 Page 16*

5 Q. Please explain the Corporate Insurance adjustment for the historic test year.

6 A. Corporate insurance includes property insurance premiums, workers
7 compensation premiums, and other miscellaneous premiums. The premium
8 policies are primarily on a fiscal year ending June of each year. The historic
9 adjustment annualizes at the monthly May 2013 premium level which mostly
10 reflects premiums paid in mid-2012 with effective periods of July 1, 2012 to June
11 30, 2013. Detailed support for these adjustments has been provided on Exhibit 4,
12 Schedule 2, Page 9.

13 Q. Please explain the further adjustment to Corporate Insurance expense for the
14 future test year and fully forecasted rate year.

15 A. The claim for Corporate Insurance in the future test year is \$2,875,768 and
16 incorporates an anticipated growth in corporate insurance of 5% over the
17 annualized historic test year level. This percentage increase was provided by
18 Columbia's corporate insurance representative and the adjustment is shown on
19 Exhibit 104, Schedule 2, Page 16. Similarly, the claim for the fully forecasted rate
20 year is \$3,019,558 and incorporates growth in corporate insurance of 5% over the
21 future test period.

Injuries and Damages

Exhibit 4: *Schedule 1 Line 10; Schedule 2, Page 10*

Exhibit 104: *Schedule 1 Line 10*

Q. Was an adjustment made for injuries and damages?

A. Yes. The historic test year expense level for injury and damages of \$499,844 represents an amount including both actual experience and adjustments to an injury and damages accrual account. An adjustment of \$127,011 was made to represent a five (5) year average actual experience in real dollars using a Gross Domestic Product ("GDP") Deflator. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 10. Other than inflation components, no further adjustment was made for the future test year and fully forecasted rate year.

Company Memberships

Exhibit 4: *Schedule 1 Line 12; Schedule 2 Page 11*

Exhibit 104: *Schedule 1 Line 12*

Q. Please explain the adjustments made for Company memberships.

A. The historic test year expense for company memberships has been adjusted for two items. First, an adjustment of \$12,229 was made to reflect a decrease in historic test year American Gas Association dues. This adjustment is shown on Exhibit 4 Schedule 2 Page 11 Line 17. Second, the future test year and fully forecasted rate year claims have been adjusted for inflation. This along with all other inflationary adjustments is addressed later in my testimony.

Utilities and Fuel Used in Company Operations

Exhibit 4: Schedule 1 Line 13; Schedule 2 Page 12

Exhibit 104: Schedule 1 Line 13

Q. What does the historic test year \$319,883 adjustment for Utilities and Fuel used in Company Operations represent?

A. This \$319,883 decrease to total historic test year utilities and fuel used in company operations of \$753,877 was made to recognize inclusion of this amount as both gas cost recovery of and gas purchase expense by Witness Bell. Columbia includes the expenses associated with gas used in company operations when establishing its gas cost recovery rates. The purchased gas is recorded as system supply and then reclassified from gas purchase to O&M expense. Therefore, it is necessary to remove the amount above from O&M for the purposes of calculating base rates and appropriately show this same level of expense in gas purchase expense along with an offsetting gas recovery level. The remaining historic test year level of \$433,994 represents other utility costs, such as electric, not recovered through the 1307(f) process. This historic level has been inflated to develop the future test year level of \$442,023 and then again to develop the fully forecasted rate year of \$448,918 which is included in Columbia's base rate claim.

Uncollectible Accounts Expense

Q. Please explain Columbia's claim for recovery of uncollectible accounts expense.

1 A. Two major categories of uncollectible accounts have been recorded historically
2 and have been represented in the development of cost of service support. These
3 two categories are "normal" (or non-CAP) uncollectible accounts and Customer
4 Assistance Program ("CAP") uncollectible accounts.

5 Normal uncollectible has been developed on Exhibit 4, Schedule 2, Page 13 and 14
6 for the historic test year and Exhibit 104, Schedule 2, Page 17 for the future test
7 year and fully forecasted rate year. The CAP uncollectible has been developed on
8 Exhibit 4, Schedule 2, Page 15 for the historic test year and Exhibit 104, Schedule
9 2, Page 18 for the future test year and fully forecasted rate year.

10 **Normal Uncollectible Accounts**

11 (Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

12 **Exhibit 4:** Schedule 1 Line 14 & 15; Schedule 2 Pages 13 and 14

13 **Exhibit 104:** Schedule 1 Line 14 & 15; Schedule 2 Page 17

14 Q. Please explain the development of the historic test year normal uncollectible
15 accounts expense.

16 A. Exhibit 4, Schedule 2, pages 13 and 14 set forth the development of a percentage
17 for uncollectible accounts related to normal charge offs recovered through base
18 rates. The schedules also calculate a three year average write off for large volume
19 customers.

20 The write off percentage for charge offs related to normal customers recovered
21 through base rates is calculated based on comparing the three-year average of

1 write-offs for normal uncollectible accounts expense to billed revenue. Several
2 adjustments to billed revenue are necessary to develop the write off percentage.
3 First, account write-offs lag billed revenue by approximately 120 days or 4
4 months. This lag in days includes consideration for the time between original
5 billing and an account being placed into final status, as well as consideration for
6 the average time between an account being placed into final status and
7 termination of service, which is when the account is written-off. I have used
8 billed revenue for the twelve months ended January of each year to appropriately
9 reflect the lag (4 months) between the billing and write-off of accounts.

10 Q. What other adjustments have been made to billed revenue?

11 A. Columbia's Distributive Information System ("DIS") billing system is used to bill
12 all residential and small business accounts; and therefore, includes revenues
13 applicable to CAP customer accounts. Line 2 of the previously referenced
14 exhibits, titled, "Total DIS Billed Revenue", has been adjusted to remove the
15 revenue associated with Columbia's CAP, as CAP uncollectibles are accounted for
16 separately. Line 4 of the previously referenced exhibits represents adjusted
17 revenue that relates to the net write-offs as shown on Line 9 of the previously
18 referenced exhibits.

19 Q. How were the net write-offs shown on Line 9 developed?

20 A. The net write-offs shown on Line 9 represent the summation of gross charge-offs

1 and recoveries for sales and CHOICE customers.¹ The CHOICE customer net
2 write-offs are only those applicable to Columbia's CHOICE distribution revenue
3 for all CHOICE customers. All sales and CHOICE customers are billed through
4 : Columbia's DIS system.

5 Q. How are the adjusted billed revenue and net write-off amounts used in the
6 development of normal uncollectible?

7 A. The three years' adjusted revenue is added together to generate the total revenue
8 as shown on Line 4. Similarly, a three year total is developed for net write-offs.

9 An uncollectible rate is then calculated by dividing the total net write-off (charges
10 offs less recoveries) by the total adjusted revenue. This rate is then applied to the

11 annualized DIS revenue as shown on Exhibit 3, Schedule 1, Page 10 by Company

12 witness Bell (Columbia Statement No. 3) for the historic test year. The result is

13 Columbia's adjusted historic test year normal uncollectible for DIS billed
14 customers.

15 Q. Does this fully describe all adjustments made to the historic test year normal
16 uncollectible expense?

17 A. No. DIS is one of three billing systems used to bill revenue related to normal
18 uncollectible write-offs. The other billing systems are used to bill larger
19 customers including chart read customers, daily read customers, customers with

¹ Customer CHOICESM is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Pennsylvania, Inc. Choice® is a registered mark of Columbia Gas of Ohio, Inc. and its use has also been licensed by Columbia Gas of Pennsylvania, Inc.

1 multiple rate components, and non-CHOICE transportation customers. These
2 systems are the Gas Transportation System ("GTS") and Gas Measurement
3 Billing ("GMB") billing systems. A three year average net write-off was developed
4 for uncollectible accounts related to these larger customers. Columbia did not
5 include these write-off amounts in the calculation of a net write-off rate, as was
6 done for DIS billed accounts, because larger customer write-offs occur relatively
7 infrequently, but can produce disproportionate write-off amounts when they do
8 occur, as can be seen in the three-year experience write offs for these type of
9 customers.

10 Q. Please summarize Columbia's proposed normal historic test year uncollectible
11 account expense adjustments.

12 A. The historic normal uncollectible adjustment is a reduction to expense of
13 \$1,428,485 as shown on Exhibit 4, Schedule 1, Lines 14 and 15. This amount has
14 been developed by comparing an annualized DIS, GTS, and GMB net write-off as
15 described above and comparing that to the normal uncollectible expense level as
16 recorded in Columbia's test year ending May 31, 2012.

17 Q. Please explain the future test year claim for normal uncollectible accounts
18 expense.

19 A. The normal future test year uncollectible expense as claimed in this rate case is
20 shown on Exhibit 104, Schedule 1, Lines 13 and 14. The \$50,358 increase in
21 expense was made to the historic annualized normal uncollectible accounts

1 expense as a result of the increase in annualized pro-forma future test year
2 revenue at present rates as shown on witness Bell's Exhibit 103.

3 Q. Please explain the fully forecasted rate year claim for normal uncollectible
4 accounts expense.

5 A. The fully forecasted rate year uncollectible expense reflects an increase of \$11,076
6 as shown on Exhibit 104, Schedule 1, Lines 13 and 14. The \$50,358 increase in
7 expense was as a result of changes to the fully forecasted rate year revenues as
8 provided on witness Bell's Exhibit 103. This has further been adjusted to include
9 normal uncollectible accounts expense of \$1,127,195 related to the increased
10 revenue at proposed rates as a result of this rate case as shown on Exhibit 102,
11 Schedule 3, Page 6, Line 4. This additional uncollectible accounts expense was
12 developed by applying the same 1.458% write-off ratio calculated at Exhibit 4,
13 Schedule 2, Page 12 to the requested revenue increase of \$77,311,053.

14 Q. Has Columbia reflected the unbundling of uncollectibles related to gas costs?

15 A. Yes. Columbia has identified a portion of the normal uncollectibles that will be
16 collected by applying the 1.458% charge to the Purchased Gas Commodity Cost
17 ("PGCC") as the Merchant Function Charge.

18 Q. What amount is attributed to the uncollectibles related to gas costs?

19 A. Columbia has identified \$1,848,276 in the fully forecasted rate year expenses
20 associated with the unbundling of uncollectibles related to gas costs. This
21 amount is included in the O&M expense claim and is offset by the same amount

1 of revenues in Exhibit 103 as developed by witness Bell. As a result, the net
2 impact to operating income is zero and therefore does not impact the base rate
3 increase requested in this case. Please refer to Exhibit 104, Schedule 2, Page 17,
4 Line 22 for details.

5 **Rider USP Costs**

6 (Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

7 ***Exhibit 4:*** Schedule 1 Line 15 and 16; Schedule 2 Page 14

8 ***Exhibit 104:*** Schedule 1 Line 15 and 16; Schedule 2 Page 18

9 Q. Are you sponsoring an adjustment for Rider USP costs as well?

10 A. Yes. Rider USP adjustments have been made to the historic test year as shown on
11 Exhibit 4, Schedule 2, Page 15, as well as the future test year and fully forecasted
12 rate year as shown on Exhibit 104, Schedule 2, Page 18.

13 Q. Please explain the test year adjustments.

14 A. The adjustments reflected in Exhibit 4 and 104 are a result of the matching of
15 expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated
16 in Exhibits 3 and 103, Rider USP revenues are \$10,805,272 for the normalized
17 historic test year, \$10,916,171 for the future test year and \$10,858,071 for the
18 fully forecasted rate year. Consequently, the various adjustments reflect changes
19 necessary to match the expense with the revenues as determined by witness Bell.
20 As a result, the USP rider net impact to operating income is zero with the expense
21 offsetting revenues. Therefore, USP rider costs do not impact the base rate

increase requested in this case.

Advertising/Bill Inserting

Exhibit 4: Schedule 1 Line 18; Schedule 2 Page 16

Exhibit 104: Schedule 1 Line 18

Q. Was advertising adjusted for reasons other than inflation?

A. Yes. Columbia has made an adjustment to remove the expense associated with its brand advertising campaigns. Please see Exhibit 4, Schedule 2, page 16 for details.

DIMP

Exhibit 104: Schedule 1 Line 20

Q. Please explain the adjustment for DIMP related costs.

A. Witness Kitchell provides a full description of the specific operations initiatives making up the estimated \$7.570 million in incremental O&M costs that will be incurred by Columbia over the fully forecasted rate year and beyond. Columbia considers these to be ongoing costs associated with DIMP-related operations enhancements, and such costs have been included in the Company's ongoing O&M efforts as delineated on Exhibit 1, Schedule 4, Line 20.

Interest on Customer Deposits

Exhibit 4: Schedule 1 Line 21; Schedule 2 Page 17

Q. Please explain the adjustment for Interest on Customer Deposits.

A. An adjustment for interest on customer deposits is necessary to recognize the

1 expense related to interest recorded on customer deposits not included in
2 Operation and Maintenance Expense on the books and records of Columbia.
3 Customer deposits are considered a source of capital in Columbia's rate base for
4 this case and, as such, reduce rate base. This adjustment is made to recognize the
5 expense related to this source of capital. The adjustment reflects the 6% interest
6 rate on customer deposits established under Chapter 14 of the Public Utility Code
7 applied to the average customer deposit balance deducted from rate base in
8 Exhibit 8. No further adjustment is made to this item for either the future test
9 year or the fully forecasted rate year, because the Company has made no
10 projection of changes to the balance of customer deposits.

11 **Lobbying Expense**

12 ***Exhibit 4:*** Schedule 1 Line 22; Schedule 2 Page 18

13 ***Exhibit 104:*** Schedule 1 Line 22

14 Q. Please describe the lobbying expense adjustment.

15 A. An adjustment has been made for the removal of lobbying expenses related to
16 labor as well as other O&M cost drivers. As such, this adjustment has not been
17 categorized by cost driver but instead is shown as a stand-alone line item on
18 Exhibit 4, Schedule 1, Page 2, Line 22. Detail for this adjustment is provided on
19 Exhibit 4, Schedule 2, Page 18. A further adjustment related to inflation is made
20 in the future test year, which I will explain later in my testimony.

Commission, OCA, OSBA Assessments

Exhibit 4: Schedule 1 Line 23; Schedule 2 Page 20

Exhibit 104: Schedule 1 Line 23

Q. Please explain the adjustment to the historic test year expense for \$9,660.

A. The adjustment is needed to increase the historic test year expense to the most current invoice amount for Commission, Office of Consumer Advocate and Office of Small Business Advocate assessments. The normalized test year expense amount of \$1,405,234 reflects the most recent invoice amount (September 23, 2011) received at the time this testimony was created.

Charitable Contributions

Exhibit 4: Schedule 1 Line 24; Schedule 2 Page 19

Q. How were charitable contributions treated as a cost of service?

A. Charitable contributions were removed from Columbia's claim as a cost of service item. Please see Exhibit 4, Schedule 1, page 2 for details.

System Services

Exhibit 4: Schedule 1 Line 25; Schedule 2, pages 21-24

Exhibit 104: Schedule 1 Line 25; Schedule 2, pages 22-31

Q. Are you sponsoring the adjustment made on Exhibits 4, Schedule 1 and 104 Schedule 1 related to System Services?

A. No. These adjustments appear on the summary schedules of Exhibit 4 and 104, but are supported by Company witness Cogar (Columbia Statement No. 12).

Emergency Furnace Repair

Exhibit 4: Schedule 1 Line 26; Schedule 2 Page 25

Exhibit 104: Schedule Line 26

Q. Please explain the adjustments for Emergency Furnace Repair program.

A. The future test year and the fully forecasted rate year reflect a claim of \$500,000 for the Emergency Furnace Repair program. This level of funding is consistent with the approved level in Columbia's last base rate proceeding.

Research and Development - GTI

Exhibit 104: Schedule 1 Line 27; Schedule 2 Page 19

Q. Please explain the GTI adjustment on Exhibit 104, Schedule 1, Line 27.

A. In Columbia's last base rate case, the Company included a claim for recovery of funding of the Gas Technical Institute ("GTI"). The settlement in that case made no specific reference to GTI funding. Columbia subsequently did fund GTI, as explained by Company witness Krajovic (Columbia Statement No. 6). This adjustment will establish funding at \$0.50 per customer per year. Ms. Krajovic is the witness responsible for this adjustment.

Normalization – Rate Case Expenses

Exhibit 104: Schedule 1 Line 28; Schedule 2 Page 20

Q. Has Columbia included consideration for rate case expense?

A. Yes. Exhibit 104, Schedule 1, Line 28 sets forth the Company's claim for rate case expenses. The estimated expenses for this rate case reflect costs to be incurred

1 for Columbia's cost of capital witness, depreciation witness, outside counsel, and
2 incremental costs associated with legal notices, employee expenses and
3 duplicating. The entire rate case expense included for normalization is
4 \$1,045,772. Columbia proposes to normalize these costs over two years.

5 Q. How was a normalization period of two years selected?

6 A. Columbia foresees the current rate of filing base rate proceedings (three of the
7 last five years) continuing in the near future as capital spending levels continue to
8 increase rate base.

9 **NiFIT**

10 ***Exhibit 104: Schedule 1 Line 30***

11 Q. Please explain the adjustment for NiFIT costs.

12 A. Witness Fontaine provides a full description of the NiFIT project in his testimony
13 and further identifies an estimated \$2.02 million in incremental O&M costs that
14 will be incurred by Columbia over the historic, future, and fully forecasted years,
15 and slightly beyond. Additionally, Columbia has filed with the Commission a
16 request for deferral treatment for these costs. The adjustment included in this
17 Exhibit reflects Columbia's proposal to recover the incremental costs over 2
18 years. Columbia considers these to be unusual, non-recurring start up costs that
19 are outside the normal level of ongoing costs associated with IT systems. As
20 noted earlier in this testimony, the incremental NiFIT costs incurred in the test

1 year were removed from the O&M claim with the adjustment on Exhibit No. 4,
2 Schedule 1, Column 3.

3 **NCSC OPEB costs amortization**

4 ***Exhibit 4:*** Schedule 1 Line 31; Schedule 2, pages 26

5 ***Exhibit 104:*** Schedule 1 Line 31

6 Q. Are you sponsoring the adjustment made on Exhibits 4, Schedule 1 and 104
7 Schedule 1 related to NCSC OPEB costs amortization?

8 A. No. These adjustments appear on the summary schedules of Exhibit 4 and 104,
9 but are being supported by witness Schmelzer.

10 **Education and Outreach**

11 ***Exhibit 104:*** Schedule 1 Line 32

12 Q. Are you sponsoring the adjustment made on Exhibit 104 Schedule 1 related to
13 Education and Outreach?

14 A. No. These adjustments are being supported by Company witness Ford (Columbia
15 Statement No. 18).

16 **Odorization**

17 ***Exhibit 4:*** Schedule 1 Line 33

18 ***Exhibit 104:*** Schedule 1 Line 33

19 Q. Please explain the adjustment for odorization.

20 A. The Company is taking over certain odorization responsibilities that were
21 previously handled by the Company's upstream supplier. As a result, Columbia

1 will see an annual increase in O&M associated with such odorization
2 responsibilities in the amount of \$75,000. The Company's engineering group
3 provided estimates for annual operating costs and maintenance costs.

4 **York MGP costs**

5 ***Exhibit 4: Schedule 1 Line 34***

6 ***Exhibit 104: Schedule 1 Line 34***

7 Q. Please explain the adjustment related to York MGP costs.

8 A. The historic test year contained operation and maintenance costs related to the
9 York MGP site that will not be charged to expense in the future periods.
10 Therefore, it is an appropriate ratemaking adjustment to remove these costs from
11 the claim. Starting in January 2012, these costs are being treated as net negative
12 salvage and will be recovered as part of the net negative salvage amortization.

13 **Inflation**

14 ***Exhibit 104: Schedule 1 Lines 7, 10, 11, 12, 13, 18, 19, 22; Schedule 2 Page***

15 *21*

16 Q. Please explain the inflation adjustments.

17 A. An inflationary factor has been applied to those future test year expense items
18 and fully forecasted rate year expense items not adjusted otherwise and subject to
19 inflation. The inflation adjustments all have been reflected on Exhibit 104,
20 Schedule 1. The inflation is based upon the Gross Domestic Product ("GDP").
21 Detail supporting the development of this rate is provided on Exhibit 104,

1 Schedule 2, Page 21. These adjusted expenses include: outside services, injuries
2 and damages, employee expenses, company memberships, utilities and fuel used
3 in company operations, advertising, other O&M, and lobbying. The lobbying
4 adjustment is a negative amount. As I explained previously, lobbying expense is
5 reflected in a variety of cost drivers that were increased in the future test year.
6 The negative adjustment backs out these increases.

7 Q. Does this complete the presentation of adjustments the company has made to
8 O&M expenses?

9 A. Yes it does.

10 **Summary**

11 Q. Please summarize the adjustments you are sponsoring.

12 A. O&M adjustments of \$661,145 have been included for the historic test year
13 resulting in a decrease from the per books expense level of \$126,145,237 to
14 \$125,484,092. The normalized historic test year expense was further adjusted by
15 \$6,465,951 for the future test year and by \$5,803,415 for the fully forecasted rate
16 year to expenses totaling \$137,753,458 which has been included in this rate case
17 claim.

18 Q. Does this complete your Prepared Direct Testimony?

19 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

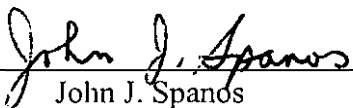
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, John J. Spanos, being Senior Vice President, Valuation and Rate Division, of Gannett Fleming, Inc., hereby state that the testimony set forth in Columbia Statement Nos. 5 and 105-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. JJS-01, JJS-1R, JJS-2R, JJS-3R, JJS-4R and JJS-5R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 12, 2013



John J. Spanos

Docket No. R-2012-2321748

SEPTEMBER 28, 2012

1 Q. Please state your name and address.

2 A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill,
3 Pennsylvania.

4 Q. With what firm are you associated and in what capacity?

5 A. I am associated with the firm of Gannett Fleming, Inc., as a Senior Vice
6 President in the Valuation and Rate Division.

7 Q. How long have you been associated with Gannett Fleming, Inc.?

8 A. I have been associated with the firm since college graduation in June 1986.

9 Q. What is your educational background?

10 A. I have Bachelor of Science degrees in Industrial Management and Mathematics
11 from Carnegie-Mellon University and a Master of Business Administration from
12 York College of Pennsylvania.

13 Q. Are you a member of any professional societies?

14 A. Yes. I am a member and current President of the Society of Depreciation
15 Professionals. I am also a member of the American Gas Association/Edison
16 Electric Institute Industry Accounting Committee.

17 Q. Have you taken the certification examination for depreciation professionals?

18 A. Yes, I passed the certification examination of the Society of Depreciation
19 Professionals in September 1997 and was recertified in August 2003 and
20 February 2008.

21

1 Q. Will you outline your experience in the field of depreciation?

2 A. In June 1986, I was employed by Gannett Fleming Valuation and Rate
3 Consultants, Inc. as a Depreciation Analyst. During the period from June 1986
4 to December 1995, I took part in the preparation of numerous depreciation and
5 original cost studies for utility companies in various industries. Depreciation
6 studies of telephone companies were performed for United Telephone of
7 Pennsylvania, United Telephone of New Jersey and Anchorage Telephone
8 Utility. My work in the railroad industry included depreciation studies for
9 Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central
10 Transportation Corporation.

11 Assignments in the electric industry included depreciation studies for
12 Chugach Electric Association, The Cincinnati Gas and Electric Company, The
13 Union Light, Heat & Power Company, Northwest Territories Power Corporation
14 and the City of Calgary - Electric System. Pipeline industry assignments
15 included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line
16 Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited
17 and Lakehead Pipeline Company.

18 My work for the gas industry included depreciation studies for
19 Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural
20 Gas Company, T. W. Phillips Gas & Oil Company, The Cincinnati Gas and
21 Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas
22 Company and Penn Fuel Gas, Inc. Assignments in the water industry included
23 depreciation studies for Indiana-American Water Company, Consumers
24 Pennsylvania Water Company and The York Water Company; and depreciation

1 and original cost studies for Philadelphia Suburban Water Company and
2 Pennsylvania-American Water Company.

3 My participation in each of the above studies included assembly and
4 analysis of historical and simulated data, field reviews, the development of
5 preliminary estimates of service life and net salvage, calculations of annual
6 depreciation, and the preparation of reports for submission to state or
7 provincial public utility commissions or federal regulatory agencies. I
8 performed these studies under the general direction of William M. Stout, P.E.,
9 the President of Gannett Fleming Valuation and Rate Consultants, Inc.

10 In January, 1996, I was assigned to the position of Supervisor of
11 Depreciation Studies. In July, 1999, I was promoted to the position of Manager,
12 Depreciation and Valuation Studies. In December, 2000, I was promoted to the
13 position of Vice-President of Gannett Fleming Valuation and Rate Consultants,
14 Inc., which is now the Valuation and Rate Division of Gannett Fleming, Inc. In
15 April 2012, I was promoted to my current position of Senior Vice President of
16 the Valuation and Rate Division. I am responsible for conducting all
17 depreciation, valuation and original cost studies, including the preparation of
18 final exhibits and responses to data requests for submission to the appropriate
19 regulatory bodies.

20 Since January 1996, I have conducted depreciation studies similar to
21 those previously listed including assignments for Pennsylvania-American Water
22 Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-
23 American Water Company; Indiana-American Water Company; Hampton Water
24 Works Company; Omaha Public Power District; Enbridge Pipe Line Company;

1 Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National
2 Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The
3 City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City
4 of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water
5 Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge
6 Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water
7 Company; St. Louis County Water Company; Missouri-American Water
8 Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas &
9 Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-
10 Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI -
11 Elizabethtown Gas Company; Cinergy Corporation - CG&E; Cinergy
12 Corporation - ULH&P; Columbia Gas of Kentucky, Inc.; South Carolina Electric
13 & Gas Company; Idaho Power Company; El Paso Electric Company; Central
14 Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-
15 Arkansas; CenterPoint Energy - Oklahoma; CenterPoint Energy - Entex;
16 CenterPoint Energy - Louisiana; NSTAR - Boston Edison Company; Westar
17 Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas
18 Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista
19 Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public
20 Service Company of North Carolina; South Jersey Gas Company; Duquesne
21 Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy
22 Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and
23 Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina;
24 Duke Energy South Carolina; Duke Energy Ohio Gas; Duke Energy Kentucky;

1 Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-
2 American Water Company; Columbia Gas of Maryland, Inc.; Bonneville Power
3 Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.;
4 B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi;
5 Entergy Louisiana, Entergy Gulf States Louisiana, the Borough of Hanover,
6 Madison Gas and Electric, Atlantic City Electric and Greater Missouri
7 Operations. My additional duties include determining final life and salvage
8 estimates, conducting field reviews, presenting recommended depreciation rates
9 to management for its consideration and supporting such rates before regulatory
10 bodies.

11 Q. What is the extent of your formal instruction with respect to utility plant
12 depreciation?

13 A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and
14 Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life
15 Analysis Using Simulation" and "Managing a Depreciation Study" programs
16 conducted by Depreciation Programs, Inc. Also, I have completed the
17 "Introduction to Public Utility Accounting" program conducted by the
18 American Gas Association.

19 Q. Have you previously testified on public utility ratemaking matters?

20 A. Yes. I have submitted testimony to the Pennsylvania Public Utility
21 Commission; the Commonwealth of Kentucky Public Service Commission; the
22 Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the
23 Public Utilities Board of New Jersey; the Missouri Public Service Commission;
24 the Massachusetts Department of Telecommunications and Energy; the Alberta

1 Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana
2 Public Service Commission; the State Corporation Commission of Kansas; the
3 Oklahoma Corporate Commission; the Public Service Commission of South
4 Carolina; the Railroad Commission of Texas – Gas Services Division; the New
5 York Public Service Commission; the Illinois Commerce Commission; the
6 Indiana Utility Regulatory Commission; the California Public Utilities
7 Commission; the Federal Energy Regulatory Commission (“FERC”); the
8 Arkansas Public Service Commission; the Public Utility Commission of Texas;
9 the Minnesota Public Utility Commission; the Maryland Public Service
10 Commission; the Washington Utilities and Transportation Commission; the
11 Tennessee Regulatory Commission; the District of Columbia Public Service
12 Commission; the Mississippi Public Service Commission; the Regulatory
13 Commission of Alaska; Delaware Public Service Commission; Virginia State
14 Corporation Commission; Colorado Public Utility Commission; Oregon Public
15 Utility Commission; Wisconsin Public Service Commission; and the North
16 Carolina Utilities Commission.

17 Q. What is the purpose of your testimony?

18 A. My testimony is in support of the depreciation studies conducted under my
19 direction and supervision for the gas plant of Columbia Gas of Pennsylvania,
20 Inc. (“Columbia” or the “Company”).

21 Q. Have you prepared exhibits presenting the results of your studies?

22 A. Yes. Exhibit No. 9 presents the results of the depreciation study as of May 31,
23 2012. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the
24 depreciation study as of May 31, 2013. Exhibit No. 109, Schedule No. 1,

1 Attachment B presents the results of the depreciation study as of June 30, 2014.
2 In addition, I am responsible for the responses to the following Filing
3 Requirements – Depreciation: 3, 4, 5, 6, 7 and 17 for Exhibit No. 5, Exhibit No.
4 9, Exhibit No. 105, and Exhibit No. 109. Exhibit No. 5 and Exhibit No. 105 are
5 summaries of the results to Exhibit No. 9 and Exhibit No. 109, respectively.

6 Q. Please describe Exhibit Nos. 9, and 109.

7 A. Exhibit No. 9, Schedule No. 1, titled "Depreciation Study - Calculated Annual
8 Depreciation Accruals Related to Gas Plant in Service at May 31, 2012," includes
9 the results of the depreciation study as related to the original cost at May 31,
10 2012. The report also includes the detailed depreciation calculations. Exhibit
11 No. 109, Schedule No. 1, Attachment A, titled "Depreciation Study - Calculated
12 Annual Depreciation Accruals Related to Gas Plant in Service at May 31, 2013,"
13 includes the results of the depreciation study as related to the estimated original
14 cost at May 31, 2013. The report also includes explanatory text, statistics
15 related to the estimation of service life, and the detailed depreciation
16 calculations. Exhibit No. 109, Schedule No. 1, Attachment B, titled
17 "Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas
18 Plant in Service at June 30, 2014," includes the results of the depreciation study
19 as related to the estimated original cost at June 30, 2014.

20 Q. What was the purpose of your depreciation studies?

21 A. The purpose of the depreciation studies were to estimate the annual
22 depreciation accruals related to gas plant in service for ratemaking purposes
23 and, using Commission-approved procedures, to estimate the Company's book
24 reserve at May 31, 2013 and June 30, 2014.

1 Q. Is the Company's claim for annual depreciation in the current proceeding based
2 on the same methods of depreciation as were used in its most recent Annual
3 Depreciation Report filed in August, 2012?

4 A. Yes, it is. For most plant accounts, the current claim for annual depreciation is
5 based on the straight line remaining life method of depreciation, which has
6 been used for over twenty years. For Accounts 391.1, 391.11, 391.12, 392, 393,
7 394, 395, 397.1, 397.24 and 398, the claim is based on the straight line
8 remaining life method of amortization. The accounts have a large number of
9 units, but small asset values representing less than 2 percent of the depreciable
10 plant. The assets represent items located in office buildings, service centers,
11 garages and warehouses. Given the difficulty in maintaining accounting records
12 for these numerous assets and high cost for periodic inventories, retirements
13 are recorded when a vintage is fully amortized, rather than as the units are
14 removed from service. All units are retired when the age of the vintage reaches
15 the amortization period. The annual amortization is based on amortization
16 accounting which distributes the unrecovered cost of fixed capital assets over
17 the remaining amortization period selected for each account.

18 Q. What group procedure is being used in this proceeding for depreciable
19 accounts?

20 A. The average service life procedure is used in the current proceeding for plant
21 installed prior to 1976 and the equal life group procedure for 1976 and
22 subsequent vintages. This calculation has been used in the same manner as the
23 Company's most recent annual depreciation reports.

24 Q. Is the Company's claim for accrued depreciation in the current proceeding
25 made on the same basis as has been used for over twenty years?

1 A. Yes. The current claim for accrued depreciation is the book reserve brought
2 forward from the book reserve approved by the Commission in the last
3 proceeding.

4 Q. How was the book reserve used in the calculation of annual depreciation?

5 A. The book reserve by account was allocated to vintages to determine original cost
6 less accrued depreciation by vintage. The total annual accrual is the sum of the
7 results of dividing the original costs less accrued depreciation by the vintage
8 composite remaining lives.

9 Q. How was the book reserve at May 31, 2013 estimated?

10 A. The book reserve at May 31, 2013, by account, was projected by adding
11 estimated accruals, salvage and the amortization of net salvage, and subtracting
12 estimated retirements and cost of removal from the book reserve at May 31,
13 2012. Annual accruals were estimated using the annual accruals calculated as
14 of May 31, 2012. For most accounts, salvage and cost of removal were
15 estimated by (1) expressing actual salvage and cost of removal as a percent of
16 retirements by account, for the most recent five-year period, and (2) applying
17 those percents to the projected retirements by account. For the purpose of
18 calculating the annual accruals, the projected book reserve by account was
19 allocated to vintages based on calculated accrued depreciation at May 31, 2013.

20 Q. Was the book reserve at June 30, 2014 estimated using the same methodology?

21 A. Yes.

22 Q. Has a service life study of the Company's gas utility property been performed?

1 A. Yes. The most recent service life study was performed as of December 2011.
2 The service life study is the basis for the service lives I used to calculate annual
3 accruals.

4 Q. Briefly outline the procedure used in performing the service life study.

5 A. The service life study consisted of assembling and compiling historical data
6 from the records related to the gas utility plant of the Company; statistically
7 analyzing such data to obtain historical trends of survivor characteristics;
8 obtaining supplementary information from management and operating
9 personnel concerning Company practices and plans as they relate to plant
10 operations; and interpreting the above data to form judgments of service life
11 characteristics.

12 Iowa type survivor curves were used to describe the estimated survivor
13 characteristics of the mass property groups. Individual service lives were used
14 for major individual units of plant, such as distribution buildings housing
15 offices and shops. The life span concept was recognized by coordinating the
16 lives of associated plant installed in subsequent years with the probable
17 retirement date defined by the life estimated for the major unit.

18 Q. What statistical data were employed in the historical analyses performed for the
19 purpose of estimating service life characteristics?

20 A. The data consisted of the entries made to record retirements and other
21 transactions related to the gas plant during the period 1939-2011. The year
22 1939 is the first year continuing property records were maintained. These
23 entries were classified by depreciable group, type of transaction, the year in
24 which the transaction took place, and the year in which the plant was installed.

1 Types of transactions included in the data were plant additions, retirements,
2 transfers, and balances. In the presentation of service life statistics, only the
3 significant exposure points that were utilized in determining survivor curves
4 were plotted. This process is utilized to show my judgment in service life
5 determinations.

6 Q. What was the source of these data?

7 A. They were assembled from Company records related to its gas plant in service.

8 Q. Were the methods used in the service life study the same as those used in other
9 depreciation studies for gas utility plant presented before this Commission?

10 A. Yes. The methods are the same ones that have been presented previously for
11 Columbia Gas of Pennsylvania, Inc. and for other gas companies before the
12 Pennsylvania Public Utility Commission and that have been accepted by the
13 Commission in its past orders concerning gas utilities.

14 Q. What approach did you use to estimate the lives of significant structures such as
15 office buildings and service centers?

16 A. I used the life span technique to estimate the lives of significant structures. In
17 this technique, the survivor characteristics of the structures are described by the
18 use of interim survivor curves and estimated probable retirement dates. The
19 interim survivor curve describes the rate of retirement related to the
20 replacement of elements of the structure such as plumbing, heating, doors,
21 windows, roofs, etc. that occur during the life of the facility. The probable
22 retirement date provides the rate of final retirement for each year of installation
23 for the structure by truncating the interim survivor curve for each installation
24 year at its attained age at the date of probable retirement. The use of interim

1 survivor curves truncated at the date of probable retirement provides a
2 consistent method for estimating the lives of the several years of installation
3 inasmuch as concurrent retirement of all years of installation will occur when
4 the structure is retired.

5 Q. Has your firm used this approach in other proceedings before this Commission?

6 A. Yes, we have used the life span technique on many occasions before the
7 Pennsylvania Public Utility Commission.

8 Q. What are the bases for the probable retirement years that you have estimated for
9 each structure?

10 A. The bases for the estimates of probable retirement years are life spans for each
11 structure that are based on judgment and incorporate consideration of the age,
12 use, size, nature of construction, management outlook and typical life spans
13 experienced and used by other gas utilities for similar structures. Most of the
14 life spans result in probable retirement dates that are many years in the future.
15 As a result, the retirement of these structures is not yet subject to specific
16 management plans. Such plans would be premature. At the appropriate time,
17 studies of the economics of rehabilitation and continued use or retirement of
18 the structure will be analyzed and the results incorporated in the estimation of
19 the structure's life span.

20 Q. Are the factors considered in your estimates of service life presented in Exhibit
21 No. 109, Schedule No. 1, Attachment A?

22 A. Yes. A discussion of the factors considered in the estimation of service lives is
23 presented by account on pages II-3 through II-30 of Exhibit No. 109, Schedule
24 No. 1, Attachment A.

1 Q. Were there any material changes to life characteristics as a result of this rate
2 proceeding?

3 A. No. There was no material change in the life estimate for plant accounts or
4 subaccounts in this rate proceeding. All life estimates were based on the recent
5 annual depreciation reports when the service life studies were conducted.

6 Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment A.

7 A. Exhibit No. 109, Schedule No. 1, Attachment A is presented in three parts. Part
8 I, Introduction, sets forth the scope and basis of the study. Part II, Methods
9 Used in Study, includes the estimation of survivor curves and the calculation of
10 annual depreciation; and an explanation of the manner in which net salvage
11 was incorporated in the calculations.

12 Part III, Results of Study, presents a description of the results;
13 summaries of the depreciation calculations; graphs and tables which relate to
14 the service life study; and the detailed depreciation calculations.

15 Table 1, pages III-4 through III-6, presents the estimated survivor
16 curve, the original cost at May 31, 2013, and the book reserve and calculated
17 annual depreciation for each account or subaccount of Gas Plant. Table 2,
18 pages III-7 and III-8, presents the bringforward to May 31, 2013, of the book
19 depreciation reserve as of May 31, 2012. Table 3 on pages III-9 and III-10 sets
20 forth the calculation of the annual accruals used in the bringforward. Table 4,
21 page III-11, presents the experienced and estimated net salvage during the five-
22 year period, 2008 through 2012.

23 The section beginning on page III-12 presents the results of the
24 retirement rate analyses prepared as the historical bases for the service life

1 estimates. The section beginning on page III-143 presents the depreciation
2 calculations related to original cost. The tabulation on pages III-145 through
3 III-147 presents the cumulative depreciated original cost by year installed. The
4 tabulations on pages III-149 through III-212 present the calculation of annual
5 depreciation by vintage by account for each depreciable group of utility plant.

6 Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment B.

7 A. Exhibit No. 109, Schedule No. 1, Attachment B includes a description of the
8 results, summaries of the depreciation calculations, and the detailed
9 depreciation calculations as of June 30, 2014. The descriptions and explana-
10 tions presented in Exhibit No. 109, Schedule No. 1, Attachment A are also
11 applicable to the depreciation calculations presented in Exhibit No. 109,
12 Schedule No. 1, Attachment B. The graphs and tables related to service life
13 presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the
14 service life estimates used in Exhibit No. 109, Schedule No. 1, Attachment B
15 inasmuch as the estimates are the same for both test years. The summary tables
16 and detailed depreciation calculations as of June 30, 2014, are organized and
17 presented in the same manner as those as of May 31, 2013.

18 Q. Please outline the contents of Exhibit No. 9.

19 A. Exhibit No. 9 includes a description of the results, summaries of the
20 depreciation calculations, and the detailed depreciation calculations as of May
21 31, 2012. The descriptions and explanations presented in Exhibit No. 109,
22 Schedule No. 1, Attachment A are also applicable to the depreciation
23 calculations presented in Exhibit No. 9. The graphs and tables related to service
24 life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the

1 service life estimates used in Exhibit No. 9, inasmuch as the estimates are the
2 same for both test years. The summary tables and detailed depreciation
3 calculations as of May 31, 2012, are organized and presented in the same
4 manner as those as of May 31, 2013.

5 Q. Please use an example to illustrate the manner in which the study is presented
6 in Exhibit Nos. 9, and 109.

7 A. I will use Account 376, Mains, as my example, inasmuch as it is the largest
8 depreciable group and represents 61 percent of the original cost of depreciable
9 gas plant as of May 31, 2013.

10 The retirement rate method was used to analyze the survivor
11 characteristics of this group. The life tables for the 1939-2011 and 1977-2011
12 experience bands are presented on pages III-61 through III-68 of Exhibit No.
13 109, Schedule No. 1, Attachment A. The life tables, or original survivor curve,
14 are plotted along with the estimated smooth survivor curve, the 72-R1.5, on
15 page III-60.

16 The calculations of the annual depreciation related to the original cost
17 at May 31, 2012, of gas plant are presented by type main on pages 36 through
18 42 of Exhibit No. 9. The calculation is based on the 72-R1.5 survivor curve, the
19 attained age, and the allocated book reserve. The calculations at May 31, 2013,
20 are presented by type main on pages III-172 through III-176 of Exhibit No. 109,
21 Schedule No. 1, Attachment A and are based in part on the bringforward of the
22 book reserve. Also, the calculations at June 30, 2014 are presented by type
23 main on pages 41 through 45 of Exhibit No. 109, Schedule No. 1, Attachment B
24 and are based in part on the bringforward of the book reserve. The tabulations

1 in Exhibit Nos. 9 and 109 set forth the installation year, the original cost,
2 calculated accrued depreciation, allocated book reserve, future accruals,
3 remaining life and annual accrual. The totals are brought forward to Table 1 on
4 page 4 in Exhibit No. 9, page III-5 in Exhibit No. 109, Schedule No. 1,
5 Attachment A and on page 4 in Exhibit No. 109, Schedule No. 1, Attachment B.

6 Q. In what manner is net salvage incorporated in the depreciation calculations?

7 A. As stated on page II-38 of Exhibit No. 109, Schedule No. 1, Attachment A, no
8 adjustment for net salvage was made to the calculated annual depreciation
9 amounts. The total calculated annual depreciation set forth on page 6 of
10 Exhibit No. 9, page III-11 of Exhibit No. 109, Schedule No. 1, Attachment A and
11 on page 6 of Exhibit No. 109, Schedule No. 1, Attachment B reflects an addition
12 for the amortization of negative net salvage in accordance with the practice of
13 this Commission. The amortization is based on experience during the period
14 2007 through 2011 for the calculation as of May 31, 2012, and on experience
15 during the period 2008 through May 31, 2012, plus estimates for the last seven
16 months of 2012 for the calculation as of May 31, 2013.

17 The amortization for the June 30, 2014 calculation is based on
18 experience during the period 2009 through May 2012, plus estimates for the
19 period June 2012 through December 2013. The amounts of the five-year
20 amortizations are calculated in Table 2 on page 6 of Exhibit No. 9, in Table 4 on
21 page III-11 of Exhibit No. 109, Schedule No. 1, Attachment A and in Table 4 on
22 page 10 of Exhibit No. 109, Schedule No. 1, Attachment B.

23 Q. Have you provided a monthly bringforward to June 30, 2014, of the book
24 depreciation reserve as of May 31, 2013?

1 A. Yes, Exhibit JJS-01 attached to my testimony provides the monthly detail of the
2 book depreciation reserve and the calculated depreciation. This exhibit agrees
3 with the June 30, 2014, reserve balance as shown on Exhibit No. 109, Schedule
4 No. 1, Attachment B, Table 1.

5 Q. Does this complete your testimony at this time?

6 A. Yes, it does.

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	Book Reserve as of May 31, 2013 (2)	June 2013						Reserve at End of Period (8)	+
		Depreciation Accruals (3)	Amortization of Net Salvage (4)	Projected Retirements (5)	Projected Gross Salvage (6)	Projected Cost of Removal (7)			
							+		
		(3)	(4)	(5)	(6)	(7)	(8)		
350.20	1,931						1,931		
351.00	638,702	3,648					642,350		
352.01	799,118						799,118		
352.02	168,680						168,680		
352.10	204,329	10					204,339		
353.00	405,288						405,288		
354.00	486,445	6,996		7,500			485,941		
355.00	123,010						123,010		
374.40	608,216	2,877	67	200		82	610,878		
374.50	1,448,649	3,653	15				1,452,317		
375.34	735,027	6,275	2,133	600		474	742,361		
375.60	68,630	105	93				68,828		
375.70	1,966,894	15,157	(1,054)	200	142	8	1,980,931		
375.80	5,298	29					5,327		
376.00	160,049,117	1,377,542	115,732	822,900		246,870	160,472,621		
378.00	5,935,094	46,531	3,350	5,600		1,232	5,978,143		
379.10	88,330	463	29				88,822		
380.00	95,420,836	761,248	193,040	316,400		237,300	95,821,424		
381.00	14,250,487	69,375	(3,415)	12,800	768	(128)	14,304,543		
381.10	2,513,211	150,350		900			2,662,661		
382.00	9,897,118	56,101		18,400			9,934,819		
383.00	2,668,228	21,752	38	6,400		128	2,683,490		
384.00	2,708,811	6,293					2,713,104		
385.00	2,962,201	21,765	2,053	3,300		726	2,981,993		
387.00	54,446	1,049	451				55,946		
387.40	484,057	4,627	108				488,792		
390.10	46,085	20					46,105		
391.10	2,268,911	6,465					2,275,376		
391.11	19,977	121					20,098		
391.12	1,087,296	31,316					1,118,612		
392.00	126,367	1,257	(368)				127,256		
393.00	15,095	34					15,129		
394.00	4,666,624	32,526	(115)				4,699,035		
394.12	1,950,337	114					1,950,451		
395.00	52,880	363					53,243		
396.00	1,604,557	4,167	(1,779)				1,606,945		
397.10	793,897	7,389	38				801,324		
397.24	2,026,206	15,511					2,041,717		
397.50	651,396	4,023					655,419		
398.00	167,533	5,619	546				173,698		
	320,167,314	2,664,771	310,962	1,195,200	910	486,692	321,462,065		
Amortizable Plant									
303.00	3,687,007	133,383					3,820,390		
305.00	(1,658)						(1,658)		
362.00	(582)						(582)		
362.10	(1,985,287)		56,524				(1,928,763)		
374.20	(30,198)		453				(29,745)		
375.71	708,470	20,266					728,736		
389.20	39						39		
	2,377,791	153,649	56,977	0	0	0	2,588,417		
Nondepreciable Plant									
	0						0		
TOTAL	322,545,105	2,818,420	367,939	1,195,200	910	486,692	324,050,481		

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	July 2013						Reserve at End of Period (14)	+
	Depreciation Accruals (9)	Amortization of Net Salvage (10)	Projected Retirements (11)	Projected Gross Salvage (12)	Projected Cost of Removal (13)			
350.20							1,931	
351.00	3,648						645,998	
352.01							799,118	
352.02							168,680	
352.10	10						204,349	
353.00							405,288	
354.00	6,996		7,500				485,437	
355.00							123,010	
374.40	2,877	67	500		205		613,117	
374.50	3,653	15					1,455,985	
375.34	6,275	2,133	4,200		3,318		743,251	
375.60	105	93					69,026	
375.70	15,157	(1,054)	200	142	8		1,994,968	
375.80	29						5,356	
376.00	1,377,542	115,732	805,100		241,530		160,919,265	
378.00	46,531	3,350	26,300		5,786		5,995,938	
379.10	463	29					89,314	
380.00	761,248	193,040	316,100		237,075		96,222,537	
381.00	69,375	(3,415)	11,600	696	(116)		14,359,715	
381.10	150,350		3,400				2,809,611	
382.00	56,101		16,500				9,974,420	
383.00	21,752	38	9,000		180		2,696,100	
384.00	6,293						2,719,397	
385.00	21,765	2,053	2,900		638		3,002,273	
387.00	1,049	451					57,446	
387.40	4,627	108					493,527	
390.10	20						46,125	
391.10	6,465						2,281,841	
391.11	121						20,219	
391.12	31,316						1,149,928	
392.00	1,257	(368)					128,145	
393.00	34						15,163	
394.00	32,526	(115)					4,731,446	
394.12	114						1,950,565	
395.00	363						53,606	
396.00	4,167	(1,779)					1,609,333	
397.10	7,389	38					808,751	
397.24	15,511						2,057,228	
397.50	4,023						659,442	
398.00	5,619	546					179,863	
	2,664,771	310,962	1,203,300	838	488,624		322,746,712	
Amortizable Plant								
303.00	133,383						3,953,773	
305.00							(1,658)	
362.00							(582)	
362.10		56,524					(1,872,239)	
374.20		453					(29,292)	
375.71	20,266						749,002	
389.20							39	
	153,649	56,977	0	0	0		2,799,043	
Nondepreciable Plant								
							0	
TOTAL	2,818,420	367,939	1,203,300	838	488,624		325,545,754	

Table 2 Monthly Bringforward to June 30, 2014

August 2013							
Account	Depreciation Accruals	Amortization of Net Salvage	Projected Retirements	Projected Gross Salvage	Projected Cost of Removal	Reserve at End of Period	
(1)	(15)	(16)	(17)	(18)	(19)	(20)	
350.20						1,931	
351.00	3,648					649,646	
352.01						799,118	
352.02						168,680	
352.10	10					204,359	
353.00						405,288	
354.00	6,996		7,500			484,933	
355.00						123,010	
374.40	2,877	67	1,100		451	614,510	
374.50	3,653	15				1,459,653	
375.34	6,275	2,133	1,400		1,106	749,153	
375.60	105	93				69,224	
375.70	15,157	(1,054)	400	284	16	2,008,939	
375.80	29					5,385	
376.00	1,377,542	115,732	854,600		256,380	161,301,559	
378.00	46,531	3,350	1,500		330	6,043,989	
379.10	463	29				89,806	
380.00	761,248	193,040	303,300		227,475	96,646,050	
381.00	69,375	(3,415)	9,800	588	(98)	14,416,561	
381.10	150,350		6,800			2,953,161	
382.00	56,101		16,500			10,014,021	
383.00	21,752	38	6,400		128	2,711,362	
384.00	6,293					2,725,690	
385.00	21,765	2,053	3,300		726	3,022,065	
387.00	1,049	451				58,946	
387.40	4,627	108				498,262	
390.10	20					46,145	
391.10	6,465					2,288,306	
391.11	121					20,340	
391.12	31,316					1,181,244	
392.00	1,257	(368)				129,034	
393.00	34					15,197	
394.00	32,526	(115)				4,763,857	
394.12	114					1,950,679	
395.00	363					53,969	
396.00	4,167	(1,779)				1,611,721	
397.10	7,389	38				816,178	
397.24	15,511					2,072,739	
397.50	4,023					663,465	
398.00	5,619	546				186,028	
	2,664,771	310,962	1,212,600	872	486,514	324,024,203	
Amortizable Plant							
303.00	133,383					4,087,156	
305.00						(1,658)	
362.00						(582)	
362.10		56,524				(1,815,715)	
374.20		453				(28,839)	
375.71	20,266					769,268	
389.20						39	
	153,649	56,977	0	0	0	3,009,669	
Nondepreciable Plant							
						0	
TOTAL	2,818,420	367,939	1,212,600	872	486,514	327,033,871	

Table 2 Monthly Bringforward to June 30, 2014

September 2013							
Account	Depreciation Accruals	Amortization of Net Salvage	Projected Retirements	Projected Gross Salvage	Projected Cost of Removal	Reserve at End of Period	
(1)	(21)	(22)	(23)	(24)	(25)	(26)	
350.20						1,931	
351.00	3,648					653,294	
352.01						799,118	
352.02						168,680	
352.10	10					204,369	
353.00						405,288	
354.00	6,996		7,500			484,429	
355.00						123,010	
374.40	2,877	67	200		82	617,172	
374.50	3,653	15				1,463,321	
375.34	6,275	2,133	4,400		3,476	749,685	
375.60	105	93				69,422	
375.70	15,157	(1,054)	900	639	36	2,022,745	
375.80	29					5,414	
376.00	1,377,542	115,732	883,500		265,050	161,646,283	
378.00	46,531	3,350	3,000		660	6,090,210	
379.10	463	29				90,298	
380.00	761,248	193,040	279,500		209,625	97,111,213	
381.00	69,375	(3,415)	10,900	654	(109)	14,472,384	
381.10	150,350		1,100			3,102,411	
382.00	56,101		17,300			10,052,822	
383.00	21,752	38	6,000		120	2,727,032	
384.00	6,293					2,731,983	
385.00	21,765	2,053	3,400		748	3,041,735	
387.00	1,049	451				60,446	
387.40	4,627	108				502,997	
390.10	20					46,165	
391.10	6,465					2,294,771	
391.11	121					20,461	
391.12	31,316					1,212,560	
392.00	1,257	(368)				129,923	
393.00	34					15,231	
394.00	32,526	(115)				4,796,268	
394.12	114					1,950,793	
395.00	363					54,332	
396.00	4,167	(1,779)				1,614,109	
397.10	7,389	38				823,605	
397.24	15,511					2,088,250	
397.50	4,023					667,488	
398.00	5,619	546				192,193	
	2,664,771	310,962	1,217,700	1,293	479,688	325,303,841	
Amortizable Plant							
303.00	133,383					4,220,539	
305.00						(1,658)	
362.00						(582)	
362.10		56,524				(1,759,191)	
374.20		453				(28,386)	
375.71	20,266					789,534	
389.20						39	
	153,649	56,977	0	0	0	3,220,295	
Nondepreciable Plant							
						0	
TOTAL	2,818,420	367,939	1,217,700	1,293	479,688	328,524,135	

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	October 2013						Reserve at End of Period (32)	+					
	Depreciation Accruals (27)	+	Amortization of Net Salvage (28)	-	Projected Retirements (29)	+			Projected Gross Salvage (30)	-	Projected Cost of Removal (31)	=	
350.20												1,931	
351.00	3,648											656,942	
352.01												799,118	
352.02												168,680	
352.10	10											204,379	
353.00												405,288	
354.00	6,996				7,500							483,925	
355.00												123,010	
374.40	2,877		67		1,700				697			617,719	
374.50	3,653		15									1,466,989	
375.34	6,275		2,133		1,000				790			756,303	
375.60	105		93									69,620	
375.70	15,157		(1,054)		800		568		32			2,036,584	
375.80	29											5,443	
376.00	1,377,542		115,732		912,800				273,840			161,952,917	
378.00	46,531		3,350		1,500				330			6,138,261	
379.10	463		29									90,790	
380.00	761,248		193,040		263,200				197,400			97,604,901	
381.00	69,375		(3,415)		9,000		540		(90)			14,529,974	
381.10	150,350				800							3,251,961	
382.00	56,101				16,100							10,092,823	
383.00	21,752		38		8,600				172			2,740,050	
384.00	6,293											2,738,276	
385.00	21,765		2,053		2,900				638			3,062,015	
387.00	1,049		451									61,946	
387.40	4,627		108									507,732	
390.10	20											46,185	
391.10	6,465											2,301,236	
391.11	121											20,582	
391.12	31,316											1,243,876	
392.00	1,257		(368)									130,812	
393.00	34											15,265	
394.00	32,526		(115)									4,828,679	
394.12	114											1,950,907	
395.00	363											54,695	
396.00	4,167		(1,779)									1,616,497	
397.10	7,389		38									831,032	
397.24	15,511											2,103,761	
397.50	4,023											671,511	
398.00	5,619		546									198,358	
	2,664,771		310,962		1,225,900		1,108		473,809			326,580,973	
Amortizable Plant													
303.00	133,383											4,353,922	
305.00												(1,658)	
362.00												(582)	
362.10			56,524									(1,702,667)	
374.20			453									(27,933)	
375.71	20,266											809,800	
389.20												39	
	153,649		56,977		0		0		0			3,430,921	
Nondepreciable Plant													
												0	
TOTAL	2,818,420		367,939		1,225,900		1,108		473,809			330,011,893	

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	November 2013						Reserve at End of Period (38)	+
	Depreciation Accruals (33)	Amortization of Net Salvage (34)	Projected Retirements (35)	Projected Gross Salvage (36)	Projected Cost of Removal (37)	=		
350.20							1,931	
351.00	3,648						660,590	
352.01							799,118	
352.02							168,680	
352.10	10						204,389	
353.00							405,288	
354.00	6,996		7,500				483,421	
355.00							123,010	
374.40	2,877	67	600		246		619,817	
374.50	3,653	15					1,470,657	
375.34	6,275	2,133	1,900		1,501		761,310	
375.60	105	93					69,818	
375.70	15,157	(1,054)	800	568	32		2,050,423	
375.80	29						5,472	
376.00	1,377,542	115,732	757,000		227,100		162,462,091	
378.00	46,531	3,350	4,500		990		6,182,652	
379.10	463	29					91,282	
380.00	761,248	193,040	227,900		170,925		98,160,364	
381.00	69,375	(3,415)	9,000	540	(90)		14,587,564	
381.10	150,350		100				3,402,211	
382.00	56,101		15,800				10,133,124	
383.00	21,752	38	5,300		106		2,756,434	
384.00	6,293						2,744,569	
385.00	21,765	2,053	3,100		682		3,082,051	
387.00	1,049	451					63,446	
387.40	4,627	108					512,467	
390.10	20						46,205	
391.10	6,465						2,307,701	
391.11	121						20,703	
391.12	31,316						1,275,192	
392.00	1,257	(368)					131,701	
393.00	34						15,299	
394.00	32,526	(115)					4,861,090	
394.12	114						1,951,021	
395.00	363						55,058	
396.00	4,167	(1,779)					1,618,885	
397.10	7,389	38					838,459	
397.24	15,511						2,119,272	
397.50	4,023						675,534	
398.00	5,619	546					204,523	
	2,664,771	310,962	1,033,500	1,108	401,492		328,122,822	
Amortizable Plant								
303.00	133,383						4,487,305	
305.00							(1,658)	
362.00							(582)	
362.10		56,524					(1,646,143)	
374.20		453					(27,480)	
375.71	20,266						830,066	
389.20							39	
	153,649	56,977	0	0	0		3,641,547	
Nondepreciable Plant								
							0	
TOTAL	2,818,420	367,939	1,033,500	1,108	401,492		331,764,368	

Table 2 Monthly Bringforward to June 30, 2014

Account	December 2013					
	Depreciation	Amortization	Projected	Projected	Projected	Reserve at
	Accruals	of	Retirements	Gross	Cost of	End of
(1)	(39)	Net Salvage	(41)	Salvage	Removal	Period
		(40)		(42)	(43)	(44)
350.20						1,931
351.00	3,648					664,238
352.01						799,118
352.02						168,680
352.10	10					204,399
353.00						405,288
354.00	6,996		7,500			482,917
355.00						123,010
374.40	2,877	67	200		82	622,479
374.50	3,653	15				1,474,325
375.34	6,275	2,133	800		632	768,286
375.60	105	93				70,016
375.70	15,157	(1,054)	12,400	8,804	496	2,060,434
375.80	29					5,501
376.00	1,377,542	115,732	666,300		199,890	163,089,175
378.00	46,531	3,350	800		176	6,231,557
379.10	463	29				91,774
380.00	761,248	193,040	208,500		156,375	98,749,777
381.00	69,375	(3,415)	8,300	498	(83)	14,645,805
381.10	150,350		4,000			3,548,561
382.00	56,101		15,400			10,173,825
383.00	21,752	38	6,800		136	2,771,288
384.00	6,293					2,750,862
385.00	21,765	2,053	3,100		682	3,102,087
387.00	1,049	451				64,946
387.40	4,627	108				517,202
390.10	20					46,225
391.10	6,465		437,655			1,876,511
391.11	121		16,155			4,669
391.12	31,316		261,307			1,045,201
392.00	1,257	(368)	14,273			118,317
393.00	34		442			14,891
394.00	32,526	(115)	188,327	423		4,705,597
394.12	114					1,951,135
395.00	363		7,436			47,985
396.00	4,167	(1,779)				1,621,273
397.10	7,389	38	5,914	512	512	839,972
397.24	15,511		23,358			2,111,425
397.50	4,023					679,557
398.00	5,619	546	20,917		5,612	184,159
	2,664,771	310,962	1,909,884	10,237	364,510	328,834,398
Amortizable Plant						
303.00	133,383		1,786,645			2,834,043
305.00						(1,658)
362.00						(582)
362.10		56,524			300,000	(1,889,619)
374.20		453				(27,027)
375.71	20,266					850,332
389.20						39
	153,649	56,977	1,786,645	0	300,000	1,765,528
Nondepreciable Plant						
						0
TOTAL	2,818,420	367,939	3,696,529	10,237	664,510	330,599,925

Table 2 Monthly Bringforward to June 30, 2014

January 2014											
Account	Depreciation Accruals		Amortization of Net Salvage		Projected Retirements		Projected Gross Salvage		Projected Cost of Removal		Reserve at End of Period
(1)	(45)	+	(46)	-	(47)	+	(48)	-	(49)	=	(50)
350.20											1,931
351.00	3,648										667,886
352.01											799,118
352.02											168,680
352.10	10										204,409
353.00											405,288
354.00	6,996				3,800						486,113
355.00											123,010
374.40	2,877		67		100				41		625,282
374.50	3,653		15								1,477,993
375.34	6,275		2,133		600				474		775,620
375.60	105		93								70,214
375.70	15,157		(1,054)		600		426		24		2,074,339
375.80	29										5,530
376.00	1,377,542		115,732		408,500				122,550		164,051,399
378.00	46,531		3,350		900				198		6,280,340
379.10	463		29								92,266
380.00	761,248		193,040		200,300				150,225		99,353,540
381.00	69,375		(3,415)		3,400		204		(34)		14,708,603
381.10	150,350				7,600						3,691,311
382.00	56,101				7,100						10,222,826
383.00	21,752		38		3,800				76		2,789,202
384.00	6,293										2,757,155
385.00	21,765		2,053		1,100				242		3,124,563
387.00	1,049		451								66,446
387.40	4,627		108								521,937
390.10	20										46,245
391.10	6,465										1,882,976
391.11	121										4,790
391.12	31,316										1,076,517
392.00	1,257		(368)								119,206
393.00	34										14,925
394.00	32,526		(115)								4,738,008
394.12	114										1,951,249
395.00	363										48,348
396.00	4,167		(1,779)								1,623,661
397.10	7,389		38								847,399
397.24	15,511										2,126,936
397.50	4,023										683,580
398.00	5,619		546								190,324
	2,664,771		310,962		637,800		630		273,796		330,899,165
Amortizable Plant											
303.00	133,383										2,967,426
305.00											(1,658)
362.00											(582)
362.10			56,524								(1,833,095)
374.20			453								(26,574)
375.71	20,266										870,598
389.20											39
	153,649		56,977		0		0		0		1,976,154
Nondepreciable Plant											
											0
TOTAL	2,818,420		367,939		637,800		630		273,796		332,875,318

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	February 2014						Reserve at End of Period (56)	+					
	Depreciation Accruals (51)	+	Amortization of Net Salvage (52)	-	Projected Retirements (53)	+			Projected Gross Salvage (54)	-	Projected Cost of Removal (55)	=	
	(51)		(52)		(53)				(54)		(55)		
350.20												1,931	
351.00	3,648											671,534	
352.01												799,118	
352.02												168,680	
352.10	10											204,419	
353.00												405,288	
354.00	6,996				3,800							489,309	
355.00												123,010	
374.40	2,877		67		100				41			628,085	
374.50	3,653		15									1,481,661	
375.34	6,275		2,133		5,900				4,661			773,467	
375.60	105		93									70,412	
375.70	15,157		(1,054)		1,500		1,065		60			2,087,947	
375.80	29											5,559	
376.00	1,377,542		115,732		397,600				119,280			165,027,793	
378.00	46,531		3,350		900				198			6,329,123	
379.10	463		29									92,758	
380.00	761,248		193,040		189,000				141,750			99,977,078	
381.00	69,375		(3,415)		3,800		228		(38)			14,771,029	
381.10	150,350											3,841,661	
382.00	56,101				6,800							10,272,127	
383.00	21,752		38		3,000				60			2,807,932	
384.00	6,293											2,763,448	
385.00	21,765		2,053		1,000				220			3,147,161	
387.00	1,049		451									67,946	
387.40	4,627		108									526,672	
390.10	20											46,265	
391.10	6,465											1,889,441	
391.11	121											4,911	
391.12	31,316											1,107,833	
392.00	1,257		(368)									120,095	
393.00	34											14,959	
394.00	32,526		(115)									4,770,419	
394.12	114											1,951,363	
395.00	363											48,711	
396.00	4,167		(1,779)									1,626,049	
397.10	7,389		38									854,826	
397.24	15,511											2,142,447	
397.50	4,023											687,603	
398.00	5,619		546									196,489	
	2,664,771		310,962		613,400		1,293		266,232			332,996,559	
Amortizable Plant													
303.00	133,383											3,100,809	
305.00												(1,658)	
362.00												(582)	
362.10			56,524									(1,776,571)	
374.20			453									(26,121)	
375.71	20,266											890,864	
389.20												39	
	153,649		56,977		0		0		0			2,186,780	
Nondepreciable Plant													
												0	
TOTAL	2,818,420		367,939		613,400		1,293		266,232			335,183,338	

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	March 2014						Reserve at End of Period (62)	+
	Depreciation Accruals (57)	Amortization of Net Salvage (58)	Projected Retirements (59)	Projected Gross Salvage (60)	Projected Cost of Removal (61)	=		
350.20							1,931	
351.00	3,648						675,182	
352.01							799,118	
352.02							168,680	
352.10	10						204,429	
353.00							405,288	
354.00	6,996		7,500				488,805	
355.00							123,010	
374.40	2,877	67	1,500		615		628,914	
374.50	3,653	15					1,485,329	
375.34	6,275	2,133	4,500		3,555		773,820	
375.60	105	93					70,610	
375.70	15,157	(1,054)	300	213	12		2,101,951	
375.80	29						5,588	
376.00	1,377,542	115,732	558,500		167,550		165,795,017	
378.00	46,531	3,350	14,300		3,146		6,361,558	
379.10	463	29					93,250	
380.00	761,248	193,040	243,800		182,850		100,504,716	
381.00	69,375	(3,415)	7,900	474	(79)		14,829,642	
381.10	150,350						3,992,011	
382.00	56,101		12,800				10,315,428	
383.00	21,752	38	5,600		112		2,824,010	
384.00	6,293						2,769,741	
385.00	21,765	2,053	3,100		682		3,167,197	
387.00	1,049	451					69,446	
387.40	4,627	108					531,407	
390.10	20						46,285	
391.10	6,465						1,895,906	
391.11	121						5,032	
391.12	31,316						1,139,149	
392.00	1,257	(368)					120,984	
393.00	34						14,993	
394.00	32,526	(115)					4,802,830	
394.12	114						1,951,477	
395.00	363						49,074	
396.00	4,167	(1,779)					1,628,437	
397.10	7,389	38					862,253	
397.24	15,511						2,157,958	
397.50	4,023						691,626	
398.00	5,619	546					202,654	
	2,664,771	310,962	859,800	687	358,443		334,754,736	
Amortizable Plant								
303.00	133,383						3,234,192	
305.00							(1,658)	
362.00							(582)	
362.10		56,524					(1,720,047)	
374.20		453					(25,668)	
375.71	20,266						911,130	
389.20							39	
	153,649	56,977	0	0	0		2,397,406	
Nondepreciable Plant								
							0	
TOTAL	2,818,420	367,939	859,800	687	358,443		337,152,141	

Table 2 Monthly Bringforward to June 30, 2014

April 2014												
Account	Depreciation Accruals		Amortization of Net Salvage		Projected Retirements		Projected Gross Salvage		Projected Cost of Removal		Reserve at End of Period	
(1)	(63)	+	(64)	-	(65)	+	(66)	-	(67)	=	(68)	+
350.20											1,931	
351.00	3,648										678,830	
352.01											799,118	
352.02											168,680	
352.10	10										204,439	
353.00											405,288	
354.00	6,996				3,800						492,001	
355.00											123,010	
374.40	2,877		67		400				164		631,294	
374.50	3,653		15								1,488,997	
375.34	6,275		2,133		800				632		780,796	
375.60	105		93								70,808	
375.70	15,157		(1,054)		500		355		20		2,115,889	
375.80	29										5,617	
376.00	1,377,542		115,732		675,900				202,770		166,409,621	
378.00	46,531		3,350		21,400				4,708		6,385,331	
379.10	463		29								93,742	
380.00	761,248		193,040		297,300				222,975		100,938,729	
381.00	69,375		(3,415)		9,000		540		(90)		14,887,232	
381.10	150,350										4,142,361	
382.00	56,101				14,300						10,357,229	
383.00	21,752		38		6,400				128		2,839,272	
384.00	6,293										2,776,034	
385.00	21,765		2,053		3,400				748		3,186,867	
387.00	1,049		451								70,946	
387.40	4,627		108								536,142	
390.10	20										46,305	
391.10	6,465										1,902,371	
391.11	121										5,153	
391.12	31,316										1,170,465	
392.00	1,257		(368)								121,873	
393.00	34										15,027	
394.00	32,526		(115)								4,835,241	
394.12	114										1,951,591	
395.00	363										49,437	
396.00	4,167		(1,779)								1,630,825	
397.10	7,389		38								869,680	
397.24	15,511										2,173,469	
397.50	4,023										695,649	
398.00	5,619		546								208,819	
	2,664,771		310,962		1,033,200		895		432,055		336,266,109	
Amortizable Plant												
303.00	133,383										3,367,575	
305.00											(1,658)	
362.00											(582)	
362.10			56,524								(1,663,523)	
374.20			453								(25,215)	
375.71	20,266										931,396	
389.20											39	
	153,649		56,977		0		0		0		2,608,032	
Nondepreciable Plant												
											0	
TOTAL	2,818,420		367,939		1,033,200		895		432,055		338,874,140	

Table 2 Monthly Bringforward to June 30, 2014

Account (f)	May 2014						Reserve at End of Period (74)	+
	Depreciation Accruals (69)	Amortization of Net Salvage (70)	Projected Retirements (71)	Projected Gross Salvage (72)	Projected Cost of Removal (73)	=		
350.20							1,931	
351.00	3,648						682,478	
352.01							799,118	
352.02							168,680	
352.10	10						204,449	
353.00							405,288	
354.00	6,996		3,800				495,197	
355.00							123,010	
374.40	2,877	67	1,100		451		632,687	
374.50	3,653	15					1,492,665	
375.34	6,275	2,133	4,100		3,239		781,865	
375.60	105	93					71,006	
375.70	15,157	(1,054)	400	284	16		2,129,860	
375.80	29						5,646	
376.00	1,377,542	115,732	730,400		219,120		166,953,375	
378.00	46,531	3,350	13,100		2,882		6,419,230	
379.10	463	29					94,234	
380.00	761,248	193,040	324,100		243,075		101,325,842	
381.00	69,375	(3,415)	9,800	588	(98)		14,944,078	
381.10	150,350		1,600				4,291,111	
382.00	56,101		15,800				10,397,530	
383.00	21,752	38	7,900		158		2,853,004	
384.00	6,293						2,782,327	
385.00	21,765	2,053	3,400		748		3,206,537	
387.00	1,049	451					72,446	
387.40	4,627	108					540,877	
390.10	20						46,325	
391.10	6,465						1,908,836	
391.11	121						5,274	
391.12	31,316						1,201,781	
392.00	1,257	(368)					122,762	
393.00	34						15,061	
394.00	32,526	(115)					4,867,652	
394.12	114						1,951,705	
395.00	363						49,800	
396.00	4,167	(1,779)					1,633,213	
397.10	7,389	38					877,107	
397.24	15,511						2,188,980	
397.50	4,023						699,672	
398.00	5,619	546					214,984	
	2,664,771	310,962	1,115,500	872	469,591		337,657,623	
Amortizable Plant								
303.00	133,383						3,500,958	
305.00							(1,658)	
362.00							(582)	
362.10		56,524					(1,606,999)	
374.20		453					(24,762)	
375.71	20,266						951,662	
389.20							39	
	153,649	56,977	0	0	0		2,818,658	
Nondepreciable Plant								
							0	
TOTAL	2,818,420	367,939	1,115,500	872	469,591		340,476,280	

Table 2 Monthly Bringforward to June 30, 2014

Account (1)	June 2014					
	Depreciation Accruals	Amortization of Net Salvage	Projected Retirements	Projected Gross Salvage	Projected Cost of Removal	Reserve at End of Period
	(75)	(76)	(77)	(78)	(79)	(80)
350.20						1,931
351.00	3,652					686,130
352.01						799,118
352.02						168,680
352.10	14					204,463
353.00						405,288
354.00	6,995		7,500			494,692
355.00						123,010
374.40	2,876	73	200		82	635,354
374.50	3,651	9				1,496,325
375.34	6,275	2,131	600		474	789,197
375.60	104	96				71,206
375.70	15,163	(1,051)	200	142	8	2,143,906
375.80	35					5,681
376.00	1,377,546	115,735	818,900		245,670	167,382,086
378.00	46,536	3,355	5,600		1,232	6,462,289
379.10	457	28				94,719
380.00	761,247	193,041	330,100		247,575	101,702,455
381.00	69,372	(3,410)	12,800	768	(128)	14,998,136
381.10	150,351		900			4,440,562
382.00	56,098	(6)	18,400			10,435,222
383.00	21,747	36	6,400		128	2,868,259
384.00	6,293	1				2,788,621
385.00	21,760	2,049	3,300		726	3,226,320
387.00	1,051	453				73,950
387.40	4,628	111				545,616
390.10	24					46,349
391.10	6,467					1,915,303
391.11	121					5,395
391.12	31,313					1,233,094
392.00	1,252	(370)				123,644
393.00	32					15,093
394.00	32,526	(117)				4,900,061
394.12	109					1,951,814
395.00	367					50,167
396.00	4,162	(1,777)				1,635,598
397.10	7,390	37				884,534
397.24	15,507					2,204,487
397.50	4,023					703,695
398.00	5,625	541				221,150
	2,664,769	310,965	1,204,900	910	495,767	338,933,600
Amortizable Plant						
303.00	133,384					3,634,342
305.00						(1,658)
362.00						(582)
362.10		56,524				(1,550,475)
374.20		451				(24,311)
375.71	20,261					971,923
389.20						39
	153,645	56,975	0	0	0	3,029,278
Nondepreciable Plant						
						0
TOTAL	2,818,414	367,940	1,204,900	910	495,767	341,962,878

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

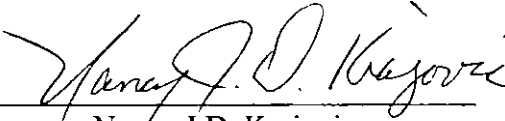
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Nancy J.D. Krajovic, being Director of Regulatory Affairs of Columbia Gas of Pennsylvania, Inc. ("Columbia"), hereby state that the testimony set forth in Columbia Statement Nos. 6, 106-R and 106-SR are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. NJDK-1, NJDK-1R, NJDK-2R and NJDK-3R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Nancy J.D. Krajovic

2-13-13
Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

DIRECT TESTIMONY OF
NANCY J. D. KRAJOVIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

September 28, 2012

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Hardship Fund Resources 20

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1 Q. Please state your name and business address.

2 A. Nancy J. D. Krajovic, Southpointe Industrial Park, 121 Champion Way,
3 Canonsburg, PA 15317

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the
6 "Company") as Director of Regulatory Affairs.

7 Q. What are your responsibilities as Director of Regulatory Affairs?

8 A. I am responsible for developing and directing rate activity on behalf of the
9 Company before the Pennsylvania Public Utility Commission ("Commission") as
10 well as coordinating and representing the Company's position in a variety of
regulatory matters and proceedings.

12 Q. What is your educational and professional background?

13 A. I hold a Bachelors of Science Degree in Accounting from Duquesne University and
14 a Master of Business Administration from the University of Pittsburgh's Katz
15 Graduate School of Business. I was employed by the Pennsylvania Public Utility
16 Commission from 1984 through 1987 as an auditor. From 1988 through 2007, I
17 held various regulatory positions at Duquesne Light Company including Regulatory
18 Analyst, Rate Design Coordinator, Project Manager, Director of Regulatory Affairs
19 and Manager of Regulatory Affairs. In those positions I acted as the primary
20 interface with the Commission in the conduct of financial and management audits
21 of Duquesne Light. Additionally, I was responsible for the interpretation and

1 administration of Duquesne's retail and supplier tariffs. In 2007, I assumed the
2 role of Manager, Commercial and Industrial Customers for Duquesne Light and
3 held that position until May, 2009. In November of 2009, I joined Columbia Gas
4 of Pennsylvania as Senior Regulatory Analyst and was promoted to my current
5 position in June of 2011.

6 Q. Have you previously testified before this Commission?

7 A. Yes, I have submitted written testimony before the Commission on Duquesne's
8 behalf at the following dockets: I-900005, M-00930404C001, R-00016854C001,
9 M-FACE0302, R-00061346 and P-00072247. I also presented oral testimony in
10 several formal customer complaint actions and at en banc hearings sponsored by
11 the Commission on energy conservation issues. Additionally, I have submitted
12 written testimony before the Commission on behalf of Columbia Gas of
13 Pennsylvania at the following dockets: R-2011-2215623, R-2012-2293303 and C-
14 2011-2248370/A-2011-2276780.

15 Q. What test years will you be addressing in this testimony?

16 A. I will be addressing the twelve-month period ending May 31, 2012 as the Historic
17 Test Year, the twelve-month period ending May 31, 2013 as the Future Test Year
18 as well as the Fully Forecasted Rate Year as the twelve-month period ending June
19 30, 2014.

20 Q. Please describe the scope of your testimony in this proceeding.

21 A. First, I am supporting the exhibits described in the following table:

Exhibit	Description
Exhibit No. 8 and Exhibit No. 108.	Historic Test Year, Future Test Year and Fully Forecasted Test Year Rate Base.
Exhibit No. 10 and 110, parts of Schedule 4 and parts of Schedule 7	Company policy with respect to replacing customers lost through attrition.
Exhibit No. 12, Schedule 3 and Schedule 8. Exhibit No. 112 Schedule 4.	Statement of over/under collection from gas cost rate and recovery of fuel costs by the utility
Exhibit No. 13 Schedule No. 4, item number 46 and Exhibit No. 113, Schedule No. 3, item number 46.	Internal and independent audit reports of the test year and prior calendar year
Exhibit No. 15 and 115, Schedules 1 and 3	Corporate history and affiliate relationships

Summary of Sponsored Exhibits

Q. Please describe Exhibit Nos. 8 and 108.

A. Exhibit No. 8 and 108 support Columbia's proposed Historic Test Year and the Fully Forecasted Rate Year Rate Base as presented in Exhibits 8 and 108 (Rate Base), respectively. Exhibit 108 also presents rate base data for a Future Test Year to demonstrate the development of the Fully Forecasted Rate Year, upon which the Company's revenue requirement for this case is based. These Exhibits will be discussed more fully in the section entitled "Rate Base" later in my testimony.

1 Q. Please describe Exhibit Nos. 10 and 110, Schedule 4.

2 A. These schedules describe Columbia's policy for replacing customers lost through
3 attrition. Columbia's policy for replacing customers lost through attrition and its
4 policy for new business are essentially identical. Columbia employs two New
5 Business Development Managers—one in the eastern part of Columbia's territory
6 and one in the western part—to identify and follow up on leads for both new
7 business as well as nonresidential customers who left Columbia's system and now
8 desire to return. In addition, Columbia uses the Dormant Account Survey
9 process as a means of identifying customers who have left the system and
10 targeting them for reconnection.

11 Q. Please describe Exhibit Nos. 10 and 110 Schedule 7.

12 A. These schedules show a reconciliation of test year DTH sales and line losses as
13 well as the gas deliveries to each customer class for the most recent 24-month
14 period. The schedule presents the customer requirements by customer class and
15 it shows supply broken down by the types of purchase. Columbia's total customer
16 requirements are reconciled with the total supply.

17 Q. Please describe Exhibit No. 12, Schedule 3 and Exhibit No. 112, Schedule 4.

18 A. Exhibit No. 12, Schedule 3 shows fuel cost in excess of base compared to fuel cost
19 recovery for the period April 1, 2010 through May 31, 2011. Exhibit 112, Schedule
20 4 refers back to Exhibit No. 12.

21 Q. Please describe Exhibit No. 12, Schedule 8.

1 A. Exhibit No. 12, Schedule 8 contains filing updates of Columbia's purchased gas
2 cost and revenues during the test year.

3 Q. Please describe Exhibit No. 13 Schedule No. 4, item number 46 and Exhibit No.
4 113, Schedule No. 3, item number 46.

5 A. These items contain copies of internal audit reports performed on Columbia's
6 operations for the test year and prior calendar year.

7 Q. Please describe Exhibit Nos. 15 and 115.

8 A. Exhibit No. 15, Schedule 1 provides a corporate history of Columbia and its
9 predecessors along with the population in the areas served by Columbia as of the
10 2010 census broken down by county and subdivision Exhibit 15, Schedule No. 2
11 provides a system map illustrating major supply points and interconnections and
12 is sponsored by Company witness Heckathorn (Columbia Statement No. 17).
13 Exhibit 15, Schedule 3 is a chart showing the affiliate relationships between
14 Columbia and affiliated companies. Exhibit 115 simply refers back to exhibit 15.

15 Q. Please describe Exhibit No. 16 and 116, Schedule 1.

16 A. Exhibit No. 16 describes Columbia's efforts to pursue delinquent accounts and
17 collect arrears. Columbia's collection activity follows the requirements of Chapter
18 56 and Chapter 14. Columbia plans no changes to its collection activity during
19 the future test year, so Exhibit 116 simply refers back to Exhibit 16.

20 Q. What other matters will you address in your testimony?

21 A. I will discuss Columbia's proposal to increase its funding of the Gas Technology

1 Institute ("GTI"), to support research done by GTI to enhance operational
2 efficiencies and safety in the gas industry.

3 Additionally I will propose that the current annual funding of Columbia's Hardship
4 Fund through a transaction with Citizens' Energy be replaced on a prospective basis
5 through the Rider USP - Universal Service Plan.

6 I will also support the Company's request for annual recovery of \$50,000
7 associated with PA 2-1-1 Southwest through Rider USP for a three year pilot
8 program proposed by the Southwestern PA United Way agencies.

9 In the settlement approved at R-2010-2215623, Columbia agreed to participate in a
10 generic investigation or rulemaking to address whether flex discounts solely as a
11 result of competition from other NGDCs should be permitted to continue and, if
12 permitted to continue, under what circumstances it will be considered appropriate.

13 Such an investigation has been initiated at Docket I-2012-2320323. In accordance
14 with the settlement provisions, Columbia has petitioned to intervene in that
15 proceeding, and Columbia's petition has been granted.

16 Lastly I note that, pursuant to the settlement referenced above, the Company has
17 undertaken a Pilot investigation of CAP customers with a CAP credit of \$1,000 or
18 more. The Pilot group includes 3,725 CAP customers and the initial results of the
19 Pilot investigation will be reported at the conclusion of the survey, as required.
20

Rate Base

Q. Is the forward looking rate year utilized by Columbia in this case different from that used in prior base rate cases?

A. Yes. Columbia elected to use the Fully Forecasted Rate Year specifically provided for in Act 11 of 2012.¹ As noted in the Commission's Final Implementation Order,

Act 11 amends Chapters 3 and 13 of the [Pennsylvania Public Utility] Code in order to reduce regulatory lag due to the use of rate case inputs that are outdated by the time new base rates become effective and, further, to provide more ratemaking flexibility for the timely recovery of prudently incurred infrastructure replacement costs.

Implementation of Act 11 of 2012, Docket No. M-2012-2293611 (Final Implementation Order entered Aug. 2, 2012). In 2007, Columbia commenced an accelerated program of priority pipe replacement and has invested \$286.5 million through 2011, replacing 1,725,362 feet of pipe. Columbia is currently on track to replace another 540,000 feet of pipe in 2012 at a cost of \$114 million. Base rate cases were filed to recover the ongoing investment in 2008, 2010 and 2011 as well as in this current proceeding.

Q. Are additional rate options available to Columbia under Act 11?

A. Yes. Act 11 also provides for a Distribution System Improvement Charge ("DSIC").

Q. Does Columbia plan to take advantage of the DSIC?

A. Yes, to the extent possible. It is the Company's intention to file for a DSIC in the first quarter of 2013 to begin recovery of eligible investment. As required, the DSIC will be reset to zero when the rates resulting from this case are implemented.

1 Q. When could Columbia next apply for a DSIC?

2 A. Under Act 11, the DSIC may only include plant not previously reflected in rate base.
3 Therefore, if Columbia's rate base plant additions claimed in this case are adopted,
4 Columbia would be able to file for a DSIC for eligible investment made after June
5 2014. Therefore, the next DSIC would likely be implemented no sooner than the
6 fourth quarter of 2014.

7 Q. Does Columbia envision that the DSIC will allow it to avoid frequent rate cases?

8 A. At the Company's current level of investment and taking into account the 5% cap
9 on distribution rates billed as recoverable by the DSIC, frequent rate cases will
10 continue to be necessary over the next several years. That said, Columbia will
11 utilize all of the regulatory tools provided by Act 11 to continue its aggressive
12 priority pipe replacement program and to mitigate the impact of future rate
13 increases on its customers.

14 Q. How does the use of the DSIC position Columbia with respect to the proxy group
15 referenced by witness Moul?

16 A. According to witness Moul, implementation of the DSIC will represent a positive
17 step that will align the Company with many of the companies that make up the
18 proxy group, as they already have rate structures or mechanisms in place that
19 address regulatory lag.

20 Q. Please explain the development of Rate Base at May 31, 2012 for the Historic Test

¹ Act 11 of 2012 was signed into law on February 14, 2012.

1 Year, May 31, 2013 for the Future Test Year and June 30, 2014 for the Fully
2 Forecasted Rate Year.

3 A. Rate Base is summarized on Exhibit 8 Page 3 and further detailed by the various
4 components in Exhibit 8 Schedules 1 through 10 for the Historic Test Year. Rate
5 Base for the Future Test Year and the Fully Forecasted Rate Year are summarized
6 on Exhibit 108 Page 3 and further detailed by the various components in Exhibit
7 108 Schedules 1 through 10. The Company's Fully Forecasted Rate Year rate base
8 claim is \$1,011,680,660.

9 Q. Please discuss the amounts included in Property Plant and Equipment Historic
10 Test Year as illustrated on Exhibit 8 Page 3.

11 A. The Company's plant in service includes plant in service per books as of May 31,
12 2012 in Account 101 and Account 106 completed construction not classified, as
13 detailed in Exhibit 8 Schedule 1. The Company's plant in service also includes the
14 in-service portion of Construction Work in Progress, Account 107 as detailed in
15 Exhibit 8 Schedule 2. The Historic Test Year also includes per books Gas Stored
16 Underground – Non-Current, Account 117 on Exhibit 8 Page 3 Line 5. Reductions
17 are included for the reserve for depreciation, as provided by Company witness
18 Spanos (Columbia Statement No. 7), and for gas lost in underground storage on
19 Lines 6 and 7.

20 Q. Please explain how the Company's Fully Future Test Year and Forecasted Rate Year
21 Property Plant and Equipment were developed.

1 A. The Company's plant in service as of June 30, 2014 as shown on Page 13 of Exhibit
2 108 Schedule 1 Column 5 is developed beginning from Column 3 of Page 1 with gas
3 plant in service at May 31, 2012 as also shown on Exhibit 8 Schedule 1. Forecasted
4 capital expenditures from June 2012 through June 2014 per the Company's
5 forecasted budget are shown in Exhibit 108 Schedule 1. Company witness Cote
6 (Columbia Statement No. 8) provides forecasted plant additions. Forecasted
7 retirements from June 2012 through June 2014, supported by Company witness
8 Spanos (Columbia Statement No. 5), are shown in Exhibit 108 Schedule 1. By
9 adding forecasted capital expenditures and forecasted non-revenue producing plant
10 and subtracting forecasted retirements, Exhibit 108 Schedule 1 reflects the net
11 forecasted plant in service included in Rate Base as of June 30, 2014.

12 Q. Please explain the purpose of Page 4 of Exhibit 8.

13 A. This page satisfies 52 Pennsylvania Code Section 53.53 I. A, item 2 of the
14 Commission's standard filing requirements, at Exhibit 8 Page 2, that the Company
15 show its rate base claim from its last base rate proceeding.

16 Q. Please explain why the Contribution in Aid of Construction amounts shown on
17 Exhibit 8 Schedule 1 have not changed from the amount reported in the last base
18 rate case except for Accounts 378.20 and 380.00 as of test year ended May 31,
19 2012.

20 A. Prior to November 2003, the Company recorded plant additions paid through
21 Contributions in Aid of Construction in plant in service (101-1000), with a

1 deduction reflected in contra accounts 101-2000, 101-3000, or 101-4000. Since
2 November 2003, the Company has netted contributions against Plant in Service
3 Account 101-1000, and thus no additional deduction is necessary. The only change
4 in the total Contribution in Aid of Construction that occurred in the Historic Test
5 Year was a retirement in Account 380.00 of \$7,431.

6 Q. Please explain Exhibit 8 Schedule 2.

7 A. This exhibit reflects the balance in construction work in progress ("CWIP") at May
8 31, 2012. However, a portion of that CWIP balance is in service, but has not yet
9 been classified to Account 101. The in-service amount is \$2,637,017, and is
10 included in the Historic Test Year rate base.

11 Q. Please explain Exhibit 108 Schedule 2.

12 A. Exhibit 108 Schedule 2 shows that forecasted CWIP, Account 107 is expected to
13 remain at the same level for the forecasted test year as it was at May 31, 2012.

14 Q. Please explain the credits to Gas plant in service on Exhibit 8 Page 3 Lines 7 and 8
15 and Exhibit 108 Page 3 Lines 5 and 6.

16 A. Line 7, Depreciation Reserve, Accounts 108 - 111 in Exhibit 8 Schedule 3 for the
17 Historic Test Year and 108 Schedule 3 for the Fully Forecasted Rate Year were
18 detailed and supplied by Mr. Spanos, by plant account, in Exhibit 5 for the Historic
19 Test Year and Exhibit 105 in the Fully Forecasted Rate Year. Line 8 Exhibit 8 Page
20 3 and Line 7 Exhibit 108 Page 3 Accum. Provision Gas Lost - Underground
21 Storage, Account 117 is per books as of May 31, 2012 for the Historic Test Year and

1 June 30, 2014 for the Fully Forecasted Rate Year.

2 Q. Did you include inventory balances in Rate Base?

3 A. Yes. As shown on Exhibit 8 Schedule 5 Materials and Supplies included in the
4 historic Rate Base is a 13 month average of the historical monthly balances in
5 Accounts 154, 186-99-12357 and 186-99-12980 materials holding clearing
6 accounts. Materials and Supplies included in the Fully Forecasted Rate Year Rate
7 Base and shown on Exhibit 108 Schedule 5 begins with May and June 2012 actual
8 balances (most recent available) and July 2012 through May 2013 balances
9 calculated by applying the GDP Deflator supported by Witness Gore (Columbia
10 Statement No. 4) in Exhibit 104 Schedule 2 Page 25 to the actual balances of July
11 2011 through May 2012.

12 Q. Did you include Prepayment balances in Rate Base?

13 A. Yes. Exhibit 8 Schedule 6 for the Historic Test Year and Exhibit 108 Schedule 6 for
14 the Fully Forecasted Rate Year show prepayments for: Corporate Insurance,
15 Account 165-0001; Prepaid Insurance I/C, Account 165-1022; Regulatory
16 Commission Fees, Account 165-9900-1161; Office of Consumer's Advocate ("OCA"),
17 Account 165-9900-11162; and Office of Small Business Advocate ("OSBA"),
18 Account 165-9900-11163. The amount in the historic Rate Base is based on a 13
19 month average of the historic monthly balances per the Company's books. The
20 amounts for the Fully Forecasted Rate Year Rate Base were determined by
21 incrementally applying the GDP Deflators supported by Company witness Gore in

Exhibit 104 Schedule 2 Page 25 to the July 2011 through June 2012 actual balances to reflect expected new prepayments as of June 2014.

Q. Did you include Gas Stored Underground in Rate Base?

A. Yes, I did.

Q. What valuation methodology is applied to Gas Stored Underground?

A. As per the Commission's March 31, 2011 Order at Docket No. P-2010-2209925, Columbia uses the weighted average cost of gas ("WACOG") methodology to value Storage Gas.

Q. Please describe the WACOG accounting methodology you applied to value the Fully Forecasted Rate Year rate base.

A. Under the WACOG accounting methodology, the actual cost and volume of the current month's injections are added to the inventory value calculated at the end of the previous month, and a new average cost per DTH is calculated for the current month. The current month's withdrawals are deducted from the balance at the new average cost per DTH. When storage gas is being injected (April through October), the inventory cost for the current month is added to the inventory cost from the previous month(s). At the end of the injection season, the storage cost for the winter is well-established. During the withdrawal season (November through March), withdrawals are made at the average price primarily resulting from the injection season.

Q. Did you include an adjustment to Gas Stored Underground in Rate Base?

1 A. Yes. I have calculated a twelve month average cost of gas to be included in Rate
2 Base.

3 Q. Do you provide exhibits supporting this storage adjustment?

4 A. Yes, I do.

5 Q. Please identify and explain these exhibits.

6 A. The supporting exhibits are Exhibit 8 Schedule 7 and Exhibit 108 Schedule 7. The
7 actual June 2011 through May 2012 injections and withdrawals are reflected on
8 Exhibit 8 Schedule 7 in columns A and E respectively. A projected monthly average
9 cost of gas is detailed in Column B. Therefore under the WACOG accounting
10 methodology, the current month's injections (Column A) are multiplied by the
11 Monthly Average Cost of Gas (Column B). The result is added to the inventory
12 value calculated at the end of the previous month (Column G), and a new weighted
13 average cost of gas per DTH is calculated (Column D) for the current month. The
14 current month's withdrawals (Column E) are multiplied by the new weighted
15 average cost of gas per DTH (Column D) and the result is deducted from the
16 cumulative balance (Column G). This method is continued every month through
17 May 2012. Line 16 calculates a twelve month average storage balance to be
18 included in the Pro Forma rate base. Exhibit 108 Schedule No. 7 repeats this
19 process from May 2012 through June 2014. Lines 27 and 28 calculate a twelve
20 month average storage balance for the Future Test Year rate base and Fully
21 Forecasted Rate Year rate base, respectively.

1 Q. Did you include Deferred Income Taxes in Rate Base?

2 A. Yes, I did. Balances as of May 31, 2012 pertaining to Deferred Income Taxes
3 included in Rate Base are shown on Exhibit 8 Schedule 8. These balances were
4 supplied by Witness Fischer (Columbia Statement No. 11) on Exhibit 7 Page 9.
5 Forecasted balances as of June 30, 2014 pertaining to Deferred Income Taxes
6 included in Rate Base are shown on Exhibit 108 Schedule 8. These balances were
7 supplied by Witness Fischer on Exhibit 107 Page 5.

8 Q. How did you determine the Customer Deposits in Rate Base?

9 A. Customer Deposits, Account 235, is the 13 month historic average, as detailed on
10 Exhibit 8 Schedule 9 for the Historic Test Year. The 13 month average for the
11 forecasted rate base, detailed on Exhibit 108 Schedule 9, reflects projected balances
12 for June 2013 through June 2014, with the entries for May and June of each year
13 based on actual data for May and June of 2012. The balances for the months of
14 July 2013 through April 2014 are the same as the balances in the months of July
15 2011 through April 2012 following the trend that deposits gradually go up in the
16 winter and down in the summer.

17 Q. How did you determine the Customer Advances for Construction to be deducted
18 from Rate Base?

19 A. Since January 2000, a credit is made to 101-Gas Plant in Service in recognition of
20 Customer Advances. Therefore, a reduction to rate base has already been included
21 for post-1999 customer advances by including the net 101-Gas Plant in Service, per

1 books. Prior to January 2000, a credit for Customer Advances was included in
2 Account 252-15560. The historic adjustment equals the per books balance at May
3 31, 2012, as detailed on Exhibit 8 Schedule 10. The future adjustment equals the
4 per books balance at June 30, 2014, as detailed on Exhibit 108 Schedule 10.
5

6 **Gas Technology Institute Funding**

7 Q. What other items are you supporting?

8 A. I am supporting a claim for Gas Technology Institute funding.

9 Q. What is the Gas Technology Institute?

10 A. The Gas Technology Institute ("GTI") is a non-profit organization that provides a
11 gas consumer research and development ("R&D") program.

12 Q. Does GTI's R&D benefit consumers of natural gas utilities like Columbia?

13 A. Yes, GTI conducts a specific type of R&D, in which the applicable technologies
14 result in improvements in safety and efficiency in gas operations that ultimately
15 benefit gas consumers. GTI is currently engaged in seventeen operations projects
16 that are intended to increase safety and operating productivity and minimize the
17 escalation of operating and maintenance costs. For a detailed list of the projects,
18 please see Exhibit NJDK-1, attached hereto.

19 Q. How do the projects benefit Columbia's customers?

20 A. The operations projects benefit Columbia's customers by reducing escalation of
21 O&M costs, increasing safety, enhancing deliverability, and increasing system

1 integrity. For example, the acoustic pipe locator will enhance safety and prevent
2 cost escalation by enabling the Company to more accurately and quickly locate
3 buried plastic gas mains and services. The horizontal direction drilling obstacle
4 detection tool will enhance safety by enabling the tool operators to locate buried
5 obstacles, including sewer pipe and other utility lines, so that the gas pipe is able to
6 by-pass these obstacles and to prevent third party damage by others.

7 As noted in Company Witness Cote's testimony, in late 2012 Columbia will be
8 partnering with the Gas Technology Institute to test the newly developed GPS\bar-
9 coding facilities identification solution that will provide sub-decimeter accuracy in
10 identifying the location of new or replacement facilities. From a broader
11 perspective, I also note that the Department of Energy recently awarded GTI over
12 \$2 million for development of natural gas storage tanks for light-duty vehicles.
13 GTI's research on natural gas issues continues to provide customers with advances
14 in the safe and cost-effective use of natural gas technologies.

15 Q. Would the private sector have invested in this R&D without the existence of GTI?

16 A. Since the prospect of a return on such an investment would be remote, private
17 sector investment in such R&D would be unlikely. Benefits are dispersed to gas
18 consumers, the general public, and gas companies, so that manufacturers would
19 not receive enough of the benefit to cover the R&D costs.

20 Q. How is GTI currently funded?

1 A. When it was established in 1977, GTI was funded through a FERC-authorized
2 surcharge on gas transported over interstate pipelines. Natural gas distribution
3 company customers have supported GTI R&D through upstream suppliers' prices
4 which were, in turn, charged under the utility's retail cost of gas. The FERC
5 discontinued that surcharge in mid-2004 and transferred the funding authority to
6 state jurisdiction.

7 Q. What other states are already participating in GTI's state funding program?

8 A. There are 28 states currently authorizing the recovery of research funding for gas-
9 consumer-interest R&D for at least one or more of the gas distribution companies
10 in their state. These are Alabama, Arizona, California, Delaware, Florida, Idaho,
11 Illinois, Kentucky, Louisiana, Maryland, Mississippi, Minnesota, Nevada, New
12 York, New Hampshire, New Jersey, New Mexico, North Carolina, Oklahoma,
13 Oregon, Pennsylvania, South Carolina, Tennessee, Texas, Utah, Virginia,
14 Washington, and Wyoming.

15 Q. Has gas R&D already been approved for recovery in Pennsylvania?

16 A. Yes. In the National Fuel Gas Distribution Company decision of November 2006,
17 the Commission approved R&D recovery from gas customers. Pennsylvania Public
18 Utility Commission, et al. v. National Fuel Gas Distribution Corporation, Docket
19 No. R-00061493 (Order entered December 4, 2006).

20 Q. Are there any other reasons why Columbia's request to include a GTI funding
21 component in its base rates should be approved?

1 A. Yes. There are a number of reasons why this request should be approved. The first
2 is economic leverage. Because 28 states have signed up for gas-consumer-interest
3 R&D, Columbia's dollars are leveraged by having other states and gas companies
4 also support the projects. The GTI program also uses these ratepayer funds to gain
5 additional leverage of state R&D and federal R&D dollars, but those would not be
6 available without the co-funding provided by the ratepayer funding. Second,
7 Columbia and its customers save resources by not needing to have a multitude of
8 experts on its staff to deal with new technical challenges as they arise. The
9 expertise is available at GTI and other research organizations, in addition to the
10 experience of participating gas company sponsors.

11 Q. What level of funding is Columbia proposing for GTI?

12 A. Columbia has included \$207,674 in its operation and maintenance expenses for
13 GTI. This amount is based on Columbia supporting the Operations Technology
14 Development ("OTD") program of GTI. Please see Exhibit 104, Schedule 2, Page 21
15 for a detailed calculation of this amount. In summary, Columbia's targeted funding
16 of GTI initiatives provides benefits to customers and should be approved.

17 Q. Do Columbia's rates currently provide for cost recovery to fund GTI?

18 A. In Columbia's prior base rate case proceeding at Docket No. R-2011-2215623, the
19 Company included a claim of \$205,414 for GTI funding in its operating and
20 maintenance expenses. Although the case was settled, there was no specific
21 language in the settlement agreement concerning the proposal to fund GTI. In

1 recognition that the rate relief provided by the settlement in that case was
2 significantly less than requested, the Company subsequently funded the GTI OTD
3 projects in the amount of \$165,000. Columbia determined this funding level based
4 on the ratio between its filed for revenue increase in the 2011 rate case and the
5 increase agreed upon by the parties, and approved by the Commission, in the
6 settlement. In this case, Columbia is again proposing to increase its funding of the
7 operational projects to \$207,674 based on per customer funding levels used by
8 other utilities as identified by GTI.

9 Q. What is the rate impact of GTI cost recovery?

10 A. At the level of funding set forth above, each customer would pay about 4.2 cents per
11 month for the benefits of GTI's research and development activities.

12 13 **Hardship Fund Resources**

14 Q. Please describe the current funding sources for Columbia's Hardship Fund used to
15 assist residential customers.

16 A. Funding for the Hardship Fund currently comes from shareholder and customer
17 contributions and matches from the Dollar Energy Fund amounting in total to
18 \$300,000 and, from time to time, the proceeds of various interstate pipeline
19 refunds and credits. Additionally, under the terms of an agreement dating back to
20 1984 and amended in 1994, each year Citizens Energy Corporation ("Citizens")

1 makes a contribution to the Dollar Energy Funds. At a minimum, the total annual
2 funding to Columbia's hardship fund is approximately \$661,000.

3 Q. Please give a brief background on Columbia's partnership with the Citizens Energy
4 Corporation.

5 A. Columbia entered into an agreement with the Citizens in 1984 that provided for the
6 purchase of gas through Citizens as a broker at a benchmark rate. Citizens would
7 then donate the margin between the benchmark price and the current spot market
8 price to the Dollar Energy Fund for disbursement to Columbia's low income
9 customers. The gas purchases from Citizens were reflected and recovered as
10 Purchased Gas Costs.

11 Q. Has this agreement continued since 1984?

12 A. Yes. However, as a result of FERC order 636, "pipeline" price of gas, which had
13 been the benchmark price for determining the fuel fund program gas purchases,
14 was eliminated. The agreement was consequently amended and approved by the
15 Commission in 1994 to maintain the annual funding. The payments by Columbia
16 to Citizens continue to be reflected as Purchased Gas Costs. Also, in accordance
17 with the Commission's Order at P-840506 entered January 17, 1989, each year the
18 Company submits a report of the funding to the Commission.

19 Q. Is Columbia proposing to make changes to this agreement?

20 A. Yes, Columbia is proposing to cancel the agreement with Citizens Energy
21 Corporation.

1 Q. Why does Columbia propose to cancel the agreement?

2 A. In 1984, all residential customers bought their gas supply through Columbia Gas.
3 Today, under CHOICE, customers can choose an alternate supplier and in doing so
4 are exempt from paying the cost of this program. There is no justification that only
5 a portion of the residential customers should support the Hardship Fund.
6 Secondly, the transaction is subject to administrative fees retained by the Citizens
7 Energy Corporation that can be avoided by canceling the contract, subject to 60
8 days notice as required by the contract.

9 Q. How does Columbia propose to replace the proceeds of the Citizens Energy
10 transaction to maintain the existing level of funding for its fuel fund program?

11 A. Columbia is proposing to increase the USP rider by \$375,000 to provide an annual
12 funding supply to its fuel fund.

13 Q. What is the current funding level under Citizens Energy Corporation?

14 A. The funding level is \$375,000. However, once Citizens takes the contracted
15 administrative fee, currently \$361,875 is left over to be directed to the Hardship
16 Fund. Eliminating Citizens as a funding conduit will reduce the administrative
17 costs, making the program more cost effective without raising the cost or reducing
18 the benefits to customers. And again, this cost would be paid by all non-CAP
19 residential customers regardless of how they purchase their gas supply. This will
20 effectively lower the cost that each customer pays to support this funding.

21 Q. Is this funding needed?

1 A. Yes. Columbia continues to see an increase in fuel fund utilization. Although
2 Columbia has petitioned the Commission and has received approval to use pipeline
3 refunds and credits, the funding stream proposed here offers a predictable
4 replacement for the Citizens Energy transaction and will actually increase the
5 minimum annual funding because of the elimination of Citizens' administrative fee.

6 Q. Is this proposed change reflected in the Exhibits filed in this case?

7 A. No. The proposed change has no effect on base rates. Rider USP Revenues in the
8 revenue requirement are calculated at the current rate and expenses adjusted to
9 reflect annual budgeted amounts, resulting in a net zero impact. Similarly, PGC
10 revenues and costs are matched, resulting in a zero base rate revenue effect. If such
11 approval is granted, the subsequent PGC reconciliation will not include payment to
12 Citizens Energy under the canceled contract.

13 **PA 2-1-1 Southwest Funding**

14 Q. Are you proposing any other changes to the funding of Universal Service Programs?

15 A. No, however I am requesting an additional \$50,000 for a pilot program to help
16 support the PA 2-1-1 Southwest hotline currently operated by the United Way of
17 Allegheny County.

18 Q. What is the PA 2-1-1- Southwest?

19 A. 2-1-1 is a nationally recognized, easy to remember phone number that quickly and
20 effectively connects people in need with resources. In the case of PA 2-1-1
21 Southwest, the connections are to human services and community resources

1 tailored to meet caller's needs within an eleven county geographic area including
2 Allegheny, Armstrong, Beaver, Butler, Fayette, Greene, Indiana, Lawrence, Mercer,
3 Washington and Westmoreland counties.

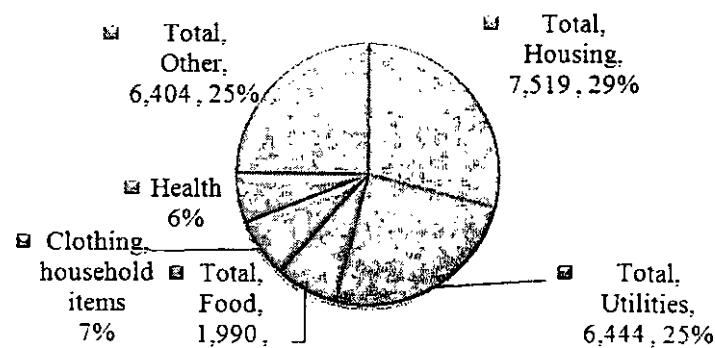
4 Q. Why is Columbia proposing to support this effort?

5 A. The Southwestern PA United Way Agencies have proposed a partnership between
6 PA 2-1-1 Southwest and several area utilities for a pilot program. This partnership
7 would seek to assist those struggling with financial hardships to connect with
8 available community resources including the Low Income Home Energy Assistance
9 Program (LIHEAP) and all other utility Universal Service Programs.

10 Q. Why should this program be funded by utility ratepayers?

11 A. In the past year, United Way of Allegheny County has found that the number of
12 calls about utilities has jumped by 21 percent (more than the increase in calls for
13 food). The calls about housing and utilities comprise the largest share of all calls to
14 PA 2-1-1 Southwest (data prior to 2-1-1's launch in July is from United Way of
15 Allegheny County's HelpLine):

16 Share of calls to PA 2-1-1 Southwest in 2011, by type



1
2
3 Q. How do you propose to fund this pilot?

4 A. Columbia proposes to increase its Rider USP by \$50,000 annually to fund this pilot
5 for a period of three years.

6 Q. As a result of this additional pilot program, will Columbia be able to reduce its
7 current administrative costs associated with outreach and education of Universal
8 Service Programs?

9 A. No. Columbia operates a toll free Universal Service hotline to assist our most
10 vulnerable and low income customers with all of their billing and payment needs.
11 This hotline has been promoted and maintained as the first place to call for
12 payment plans, weatherization assistance, hardship funds, LIHEAP and billing
13 issues. It would not be advisable for Columbia to deviate from this successful
14 model. This pilot does represent an opportunity to enhance the existing outreach
15 efforts and perhaps educate a customer segment that is not comfortable reaching
16 out to the utility for assistance. It would still be necessary for customers referred by
17 the United Way to subsequently call the hotline for specific utility related
18 information and application assistance.

19 Q. Does this complete your Prepared Direct Testimony?

20 A. Yes, it does.

Operations Technology Development Projects¹

Leveraging Consumer Technologies for Utility Operations

Determine the opportunities for using consumer information technologies (such as open source, data sharing, web editing, smart phones, and networking) to improve utility operations. An open, collaborative, web-based approach will be used for this study. This will provide operators with information regarding the capabilities of consumer technologies, potential applications, and examples from other industries that may increase efficiency, reduce costs, and reduce risk. The results of this project may lead to the development of future proposals with a focus on adapting the identified technologies to generate incremental value for gas utility operations.

Distribution Integrity Management (DIM) – Risk Mitigation Technique Optimization Tool

Develop a DIM tool that optimizes the balance between risk reduction and a finite budget to assist operators in making resource deployment decisions. The tool development includes consideration of infrastructure from the city gate station downstream to the meter set. The user would input risk tolerances and company specific costs as well as optional information such as available budgets and corporate strategies. Using this tool for decisions reduces subjectiveness and saves labor.

Evaluation of Lightweight Jackhammers

Evaluate the performance of 60-pound (lb) jackhammers compared to 90 lb jackhammers in terms of effectiveness in breaking asphalt and concrete while considering noise, ergonomics, and cost. Lightweight jackhammers will reduce injuries and noise; however they are assumed to be not as productive as heavier jackhammers. This study will use the same operators and determine the time and efficiency to fatigue while breaking specific pavement segments.

Vibratory Assistance for Soil Excavation

Investigate a method to break hard-to-excavate soils by applying set frequencies at the surface with a lightweight tool. This tool can reduce injuries associated with hand breaking and jackhammers and reduce the damage that can be caused by pneumatic clay spades, jack hammers, and water jets during the excavation process. The research will verify the technical feasibility of applying vibrations to break various types of soils.

Improving Methane Emission Estimates for Natural Gas Distribution Companies

Conduct the field measurements needed to develop emission factors of underground plastic pipelines. The study will categorize emission factors characteristics including pipe material, diameter, age, pressure, leak type/source, soil type, and the environment. The overall objective is to increase the accuracy and certainty of these emission factors so the methodology and the factors can be used by the industry for regulatory reporting as well as quantifying reductions in fugitive emissions. This project is timely and relevant as the resulting methodology will assist gas distribution utilities in complying with the recently released EPA Notice of Proposed Rulemaking (NOPR). (Note: The EPA NOPR requires utilities to report fugitive methane emissions.)

Testing and Design of Casing End Seals

Develop quantitative testing information on seal performance that shows what types of casing end seals work best under what circumstances including pipe and casing diameter, carrier pipe coating type, soil type and moisture fluctuations, casing design, temperature, depth and pressure, and length of pipe and bends. The results from this effort will allow operators to make better decisions for both new installations and seal rehabilitation. This effort focuses on 6-8 inch pipe diameters.

Instrument to Detect Transection of PE Pipe with Other Underground Conduits, Phase 1

Develop an ultrasonic-based sensing tool that will be used inside a plastic pipe immediately following a horizontal directional drill (HDD) or pneumatic soil piercing tool installation to determine if a sewer pipe or sewer lateral has transected any third party utility line (with particular emphasis on gas lines transecting sewer laterals). A laboratory breadboard prototype will be developed and tested to address this industry wide safety issue. Benefits include reducing the risk of incidents, increased safety, and expanding the use of trenchless technology.

Ethane-Only Detector

Build and test an alpha prototype ethane-only gas detector based on the same platform as the successful portable methane detector being commercialized in the second quarter of 2010 by Sensit Technologies. This ethane-only hand-held detector would be used for low concentration (ppm) leaks to detect the naturally occurring trace amounts of ethane in natural gas leaks in the field when it is needed to determine the origin of the methane leak (natural gas v. swamp gas). Benefits include immediate decision making in the field and reduced cost compared to off-site laboratory analysis of the samples.

Keyhole Technology R&D:

This R&D focuses on developing, testing, and facilitating innovative "keyhole" technologies for utility system installations, repairs, and renovations.

Hand-Held Acoustic System for Plastic Pipe Location

The benefits of this project will be reduced third party damage (due to the ability to more easily locate plastic pipe) and reduced locating costs.

Integration of Electromagnetic and Acoustic Obstacle Detection Systems for Utility Construction Operations

The objective of these projects is to provide real-time detection of underground utilities during horizontal directional drilling (HDD) operations during installation of pipes. The benefits would be reduced third party damage and reduced risk of intrusion of the gas main into other utilities during HDD.

Adoption of UV Curing for Cured-In-Place (CIP) Liners

This project will develop an ultraviolet curing process to significantly accelerate curing time and hence speed up the refurbishment process. The benefits of this project are reduced customer outage time and lower O&M costs.

Service-Applied Main Stopper

The Service Applied Main Stopper (SAMS) project objectives are to develop technology and the necessary tools that will utilize existing customer service lines and meter sets to

isolate pipe ruptures and stop the flow of gas, reduce costs by minimizing excavations through the use of the SAMS "no-dig" technology, and decrease the isolation area. This project focuses on lowering the costs associated with emergency gas shut-off due to third-party damage, through the development of an innovative tool and method of use that enables shutoffs without major excavation. The benefits of this project will be to minimize customer shutoff times, enhance safety, and lower costs.

Plastic Pipe Risk Model

The objective of this project is to develop and validate a plastic pipe risk assessment model for use in distribution integrity management. Risk-based assessment of gas distribution mains will probably be an integral part of distribution integrity management plans. However, the failure mechanisms for plastic gas mains are very different from that of steel gas pipelines or even steel distribution mains, and so a new model must be developed and validated to assess the highest-risk sections of plastic pipe for repair and replacement. Benefits will include enhanced safety and system integrity and reduced O&M costs.

Trench-less Service Installation through Keyholes

Initial efforts will focus on developing a special piercing tool to allow for the installation of plastic service lines through keyholes. (Keyhole excavations of 18 inches or less in diameter have saved excavation and repair times compared to conventional 3 foot by 4 foot holes.) The ability to install service lines through keyholes will greatly reduce the costs of hooking up new customers and replacing service lines, especially in urban areas.

Gas Interchangeability for LDC Infrastructure Integrity (NYSEARCH Project)

The objective of this study is to identify the potential effects of the increasingly diversified and changing natural gas compositions on the integrity of the gas distribution network. This would be accomplished by 'manufacturing' test gases and testing them against materials of interest. Once the materials that are affected by the varying gas compositions are identified, those infrastructure components that contain these materials would be analyzed. Benefits include enhanced safety and lower maintenance costs.

Biogas Interchangeability

Creating a renewable source of natural gas from biomass and wastes can help to enhance supply and reduce greenhouse gases as well. However, the gas infrastructure must be able to handle the resulting biogas without materials degradation. This project will identify the constituents of biogas from various sources and their potential impact on the natural gas infrastructure. Benefits are enhanced supply, reduced emissions and enhanced safety.

ⁱ Information provided by Gas Technology Institute.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

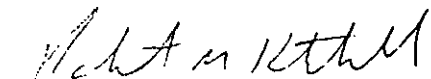
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Robert M. Kitchell, being Vice President and General Manager of Field Operations of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 7 and 107-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit No. RMK-1, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Robert M. Kitchell

2-13-13

Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

VS.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

DIRECT TESTIMONY OF
ROBERT M. KITCHELL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Robert M. Kitchell and my business address is 121 Champion Way,
3 Suite 100, Canonsburg, Pennsylvania.

4 Q. By whom are you employed and in what capacity?

5 A. I am a Vice President and General Manager of Field Operations employed by
6 NiSource Corporate Services Company. I assumed this position in May 2012, and
7 in this capacity I am accountable for overall leadership and direction for the
8 Operations areas of Columbia Gas of Pennsylvania ("Columbia" or "the Company"),
9 and Columbia Gas of Maryland ("CMD"). These responsibilities include oversight
10 of Gas Distribution, Customer Service, Metering, Plants and System Regulation,
11 and Facilities.

12 Q. Please describe your professional and educational background.

13 A. Prior to May 2012, I served as the Director of Operations Integration where I was
14 responsible for ensuring premier emergency response, ensuring that appointments
15 were met, and ensuring the proficient scheduling and dispatching of work for
16 NiSource Inc.'s ("NiSource's") natural gas distribution companies. I began my
17 career with the Northern Indiana Public Service Company ("NIPSCO"), a subsidiary
18 of NiSource, in 1977 where I held a variety of operational and leadership roles of
19 increasing responsibility. I joined NiSource's gas distribution segment in 2004 as
20 Operations Center Manager for Columbia Gas of Pennsylvania's Northern service
21 area. I then became the Operations Center Manager of Columbia's Central service
22 area in 2007 prior to being named Director of Operations Integration in 2009. I
23 hold an Associate's degree in supervision from Purdue University and a Bachelor's

1 degree in organization management from Calumet College of St. Joseph.

2 Q. Have you previously testified before this or any other regulatory Commission?

3 A. No, I have not.

4 Q. Please describe your membership in, or affiliation with, any industry organizations.

5 A. I hold a professional membership with the Southern Gas Association.

6 Q. What is the purpose of your testimony?

7 A. I will describe the division of staff between the traditional field operations
8 department and the newly created Pipeline Safety and Compliance Organization
9 that is being overseen by Company witness Cote (Columbia Statement No. 8). I will
10 also provide testimony in support of some of the operations initiatives Columbia
11 has previously undertaken and continues to expand upon to improve its overall
12 customer delivery performance, and finally I will testify regarding Columbia's
13 incremental Operations and Maintenance ("O&M") needs associated with the
14 Company's increased level of capital investment in 2012 and beyond.

15 Q. Please discuss the division of staff as impacted by the newly created Pipeline Safety
16 and Compliance Organization overseen and discussed by witness Cote.

17 A. The field operations personnel in the department I oversee are Columbia Gas of
18 Pennsylvania employees. In turn, many of the employees in witness Cote's Pipeline
19 Safety and Compliance Organization are employed by NiSource Corporate Services
20 Company. This is because the Pipeline Safety and Compliance Organization
21 supports Columbia affiliates in addition to supporting Columbia (as described by
22 Mr. Cote) and employees of that organization allocate their time accordingly. The
23 Columbia employees that I oversee manage the field operations, metering, plant

1 and system regulation and facilities necessary to maintain and operate Columbia's
2 physical gas distribution system. In addition, my department provides customer
3 service to Columbia customers while in the field.

4 Q. Witness Cote discusses Columbia's leak history and efforts to reduce overall system
5 leakage. What are some of the other ways that Columbia has improved its customer
6 delivery performance over the last several years?

7 A. As discussed in previously filed rate cases, beginning in 2006, Columbia launched a
8 number of specific initiatives to improve its operating performance, and the
9 operating characteristics of its system. Some of the practice enhancements or
10 procedure changes regarding operating performance specific to customer delivery
11 performance include:

- 12 • Increase Columbia's 60 minute or less Emergency Response Rates.
13 Emergency response rates are integral to public safety. The sooner the first
14 Columbia responder arrives at a possible emergency, the quicker the
15 situation can be stabilized, made safe, and ultimately remediated. Since
16 2006, Columbia has undertaken a very structured approach to improving its
17 emergency response times including the addition of field operations
18 positions, additional off hours shifts, providing all field employees with GPS
19 enabled cell phones (allowing the Dispatch Group to identify
20 closest\quickest responder when dispatching field technicians to
21 emergencies), and driving an increased focus with all employees on the need
22 to respond to reported emergencies as quickly and as safely possible. In
23 addition, Columbia continues to make enhancements in an effort to keep

emergency response rates down. Starting in 2011, Columbia implemented an automated crew call out and resource management system to call the service technician located closest to an issue that requires a response after hours. Columbia also negotiated language to our labor contracts which requires a service technician to be on Emergency Responder Rotation so that we have an initial responder available 24 hours a day, 365 days a year. The results of these focused efforts have been significant, and a comparison of the data showing the 60 minute or less response rates from 2006 to 2012 (June YTD results) is as follows:

	2006	2012 (June YTD)
➤ Normal Hours	98.13%	99.45%
➤ After Hours	92.34%	97.21%
➤ <u>Weekends & Holidays</u>	<u>88.99%</u>	<u>96.83%</u>
➤ Total Performance	97.00%	98.58%

- Increase the number of Columbia's on-time customer appointments as measured by the overall annual percentage of on-time appointments met. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service related activities, it is incumbent on the Company to be as efficient as possible with the customers' time. Therefore, in 2007 Columbia began to focus specific attention on improving its percentage of on-time appointments. It did so by tasking the Integration Center (Columbia's Centralized Scheduling and Dispatch Center) to improve field employees'

1 daily schedules to align more closely with the needs of customer
2 appointments, and to shift non-emergency work when possible to meet
3 appointments that, for a variety of reasons, might otherwise be missed. As a
4 result of these efforts, Columbia has been able to improve its on-time
5 appointment rates from 97% in 2006, to a rate of 98.6% in 2011.

6 Q. Has Columbia made any other O&M changes in 2012 relating to operating
7 performance?

8 A. Yes, as discussed in more detail by witness Cote, consistently, Columbia's number
9 one measured system risk is third-party damage, and this risk is reflected as the
10 number one priority in Columbia's Distribution Integrity Management Program
11 Plan ("DIMP"). As such, Columbia has deemed it necessary to hire four additional
12 in-house locators and three additional damage prevention coordinators. These
13 additional locators were hired in April 2012. The three damage prevention
14 coordinators were hired to visit job sites and train third party contractor crews in
15 safe excavating practices, and also visit the job sites of frequent damagers. The
16 costs associated with hiring these seven full time employees are included in the
17 Company's historic test year labor and benefits claim sponsored by Company
18 witness Gore (Columbia Statement No. 4).

19 Q. Please describe the Company's reduction in OSHA recordable injuries.

20 A. At the end of 2006, Columbia had 48 Occupational Health and Safety
21 Administration ("OSHA") recordable injuries, while during the entire 2011 calendar
22 year that number had declined to only 9 OSHA recordable injuries. This 82%
23 reduction was achieved by an aggressive management initiative that included:

- 1 • Training for all employees on numerous safety practices such as ergonomics,
2 preventing trips, slips and falls, body mechanics, staying focused on task,
3 mandatory driver safety program participation, and other improvement
4 practices.
- 5 • Forming a state-wide employee safety team comprised of front line workers,
6 leaders, and managers from all locations to make recommendations on
7 safety improvement opportunities, to review the root cause analysis that
8 takes place with every OSHA recordable injury and preventable vehicle
9 accident, review new tools and discuss the correct tools for the type of work
10 that is performed, and to act as a steering committee for the local safety
11 programs.
- 12 • Forming local employee safety teams made up of leaders and front line
13 workers from each operating center to make recommendations on safety
14 improvement opportunities and tooling.
- 15 • Creating an employee safety audit program which required leaders to
16 perform safety audits on field employees' activities, and to provide feedback
17 on an employees' safety performance.
- 18 • Creating a jobsite safety check list for field activities that requires field
19 personnel to evaluate the hazards associated with each field task before they
20 perform that task.

21 Q. Mr. Cote's testimony indicates there will be an increase in O&M expense associated
22 with the planned volume of capital and O&M work for 2012 and beyond. Please
3 discuss the amount of the increase.

1 A. Columbia has identified an incremental \$9.25 million of annual O&M expense
2 based on the increased capital projects and initiatives that have begun in 2012.

3 Q. How is the incremental \$9.25 million of O&M expense you are sponsoring in your
4 testimony included in the case?

5 A. In summary, the total incremental amount of O&M Columbia is seeking in this case
6 (\$9.25 million) has been split into four categories: (1) rents and leases, (2) new
7 labor and benefits, (3) reassignment of the Company's labor force from capital to
8 O&M, and (4) DIMP. As detailed in Exhibit RMK-1 attached to my testimony: (1)
9 the \$350,000 associated with the new Alpine Point Operations Center that I
10 discuss later in this testimony is accounted for in Columbia's rents and leases
11 expense, (2) the \$250,000 associated with three mapping GPS mapping technicians
12 detailed below, is included in Columbia's Labor and Benefits expense, (3) the
13 reassignment of Company labor, which accounts for \$1,080,000 of the incremental
14 \$9.25 million, is reflected through the Company's labor capitalization adjustment
15 claim in this case, and (4) the remaining \$7,570,000 increase to O&M that makes
16 up the balance of the \$9.25 million request in this case has been included in the
17 Cost of Service sponsored by witness Gore as a category entitled "DIMP."

18 Further explaining the reassignment of labor force category referenced above, over
19 the past 18 months Columbia has been using Company employees who have
20 historically performed O&M to support capital projects as the capital program has
21 continued to ramp up to the full run rate we are now experiencing. As a result,
22 Columbia's capitalization ratio for the historic test year ending May 31, 2012 is
23 higher than capitalization ratios Columbia has experienced in the past and higher

1 than Columbia intends the ratio to be going forward. Company witness Gore
2 discusses how the Company has adjusted for this fact. Operationally, Columbia is
3 staffing its operations and field employees in such a way that much of the O&M is
4 being brought back in house and we are lining up contractors to perform the capital
5 work. This effort is demonstrated by the fact Columbia has brought the locating
6 function entirely back in house, when previously it was outsourced. The reasons for
7 bringing O&M related activities back in house include the fact that we believe our
8 own employees are more suited to handle the day to day operations and
9 maintenance activities while contractors should be performing capital work. For
10 the \$9.25 million in incremental O&M alone, we project \$1,080,000 of that amount
11 to be attributable to labor and benefits for employee labor that will be expensed
12 rather than used in capital projects.

13 Q. Please describe the reasons for the \$9.25 million increase in Columbia's O&M
14 expense.

15 A. Columbia's incremental O&M needs can be attributed to the following items: right-
16 of-way clearing activities, atmospheric corrosion efforts, ongoing maintenance of
17 exposed cathodically protected steel, continued efforts to reduce the backlog of
18 open Type 2 leaks, sewer line cross-boring efforts, a new operations center,
19 enhanced mapping technology based on GPS locating technology, compliance with
20 federal standards regarding maximum allowable operating pressure ("MAOP")
21 verification efforts, increase to public awareness plan spending (commonly referred
22 to as RP 1162 spending) regarding PA One Call efforts in compliance with federal

1 code,¹ and training and staffing efforts at a storage facility owned and operated by
2 the Company. Each of these items is discussed below.

3 Q. Please discuss the increased O&M expense associated with right-of-way clearing.

4 A. A right-of-way that is clear of incompatible and overgrown vegetation, such as trees
5 and brush, is important to Columbia. It helps to identify the location of pipeline
6 facilities for those that are performing construction or routine maintenance work
7 and for responding to emergencies near the buried pipeline. To ensure the safety of
8 our underground facilities, Columbia needs direct and immediate access to its
9 buried pipelines. This enables us to conduct testing on the underground pipeline to
10 monitor its integrity and to perform general maintenance and repairs as needed. In
11 the event of an emergency, a clear right of way is necessary for both Columbia and
12 emergency response officials. Any obstructions can inhibit our ability to respond
13 safely. Additionally, this overgrowth creates a material risk of slips, trips and falls,
14 which constitutes a safety hazard whenever Columbia must perform necessary
15 maintenance on these facilities. Columbia has more overgrowth issues than any of
16 Columbia's affiliated natural gas distribution companies and an incremental \$1
17 million in O&M that is requested in this area will afford Columbia the necessary
18 resources to manage the right-of-way growth appropriately. Columbia has
19 identified more than 630 miles of right-of-way vegetation management needing
20 additional attention, and right-of-way vegetation is under continuing review.

21

¹ Federal code (49 C.F.R. 192.616) requires pipeline operators to have a continuing public education program that follows the guidance provided in the American Petroleum Institute's Recommended Practice ("RP") 1162.

1 Q. Please explain the increased O&M expense associated with atmospheric corrosion
2 remediation.

3 A. Columbia is accelerating its efforts to remediate the atmospheric corrosion of
4 Company facilities associated with above ground structures including main lines
5 attached to bridges, measurement and regulation stations and large customer
6 delivery points at an incremental \$1 million in O&M expense annually. Specifically,
7 the remediation is a manual process, which entails scraping down the oxidation,
8 then painting and applying protective coating to the facilities.

9 Q. Please explain the increased O&M expense associated with addressing exposed
10 coated cathodically protected steel.

11 A. Pursuant to Federal Code (49 C.F.R. 192.327) coated, cathodically protected mains
12 must have a minimum of 24 inches of cover. Columbia has experienced floods,
13 washouts and earth movement in Pennsylvania that has resulted in a number of
14 situations where our facilities have become exposed. Columbia must be able to
15 continue addressing these issues by lowering its facilities or filling the washout,
16 then Rip-Rapping the area to prevent further washouts. Columbia anticipates
17 spending an incremental \$1.5 million annually in O&M on these efforts in 2013 and
18 beyond. At this time, Columbia has identified 19 projects ranging from \$50,000 to
19 \$500,000 each.

20 Q. Please explain what you mean by "Rip-Rap."

21 A. "Rip-rapping" is used to create a foundation by enclosing rocks in square metal
22 cages in order to prevent earth movement.

1 Q. In 2006, Columbia commenced an initiative to reduce the number of Type-2 leaks
2 as discussed by Company witness Cote. Please explain the Company's proposed
3 enhancements to this initiative and the incremental O&M associated with such
4 work.

5 A. While Columbia continues to replace bare steel and cast iron on an accelerated
6 basis, it will take time and much more of the system to be replaced before the
7 overall leakage rate decreases. Until all of the bare steel is replaced, Columbia's
8 existing bare steel continues to erode and new Type-2 leaks are discovered with
9 each survey. In order to get ahead of the curve and maintain a downward pressure
10 on the open Type-2 leaks, Columbia must start reducing the Type-2 leaks on a
11 more accelerated basis. Columbia proposes to spend \$2.5 million in incremental
12 annual O&M to accelerate this effort. Columbia seeks this incremental O&M for
13 materials, vehicles, equipment, restoration of property and other purchases
14 necessitated by leak repair.

15 Q. Please discuss the increased O&M expense associated with sewer line cross-bore
16 conflict remediation effort.

17 A. Prior to 2008, it was not the practice of most gas companies (Columbia included) to
18 dig test holes at each sewer crossing when using trenchless excavation practices.
19 This is a significant safety issue because, typically, gas service is on when a gas
20 utility's facilities are struck, and the end result is gas blowing in a sewer line until it
21 is automatically shut down by an excess flow valve, or until the utility can get the
22 service shut off if an excess flow valve has not been installed. In the case of main
23 lines, excess flow valves are not utilized and manual valves would need to be shut

1 off to stop the gas flow. To identify whether there are cross-bore conflicts that need
2 to be resolved, Columbia is planning to use camera-scoping technology to view
3 sewer lines that it has crossed while conducting trenchless excavation. This effort
4 will amount to an annual incremental O&M expense of \$1 million which is for
5 outside resources and data management generated by this initiative.

6 Q. Please discuss the increased O&M expense associated with the Alpine Operation
7 Center in Washington, Pennsylvania.

8 A. As a result of leases expiring on multiple Columbia building sites, and the
9 expansion of Columbia's engineering and construction workforces to accommodate
10 the Company's accelerated infrastructure replacement initiative, Columbia moved
11 to a new PA Central Operation Center in August 2012. The move allowed Columbia
12 to consolidate two previous building work sites and a number of support staff who
13 routinely work together into one building. The net incremental leasing cost is
14 approximately \$350,000 per year. In addition to consolidating what was
15 previously two building work sites, the new work space allows for Columbia to store
16 material and equipment on site at the PA Central Operations Center.

17 Q. Please discuss the incremental O&M expense associated with hiring GPS mapping
18 technicians.

19 A. The Company will hire three Pennsylvania-based mapping technicians by the end of
20 December 2012, whose roles are to support the deployment of GPS locating
21 technology and system field records. Columbia will experience approximately
22 \$250,000 in incremental O&M annually for salary and benefits for these
23 employees. The estimated salary and benefits are calculated in witness Gore's

1 analysis.

2 Q. Is there any incremental O&M expense associated with increased state and federal
3 regulations?

4 A. Yes, there is. In compliance with federal requirements Columbia is obligated to
5 review all necessary records on pipelines operating above 20% of specified
6 minimum yield strength. Specifically, Columbia will be required to dig test holes on
7 the facilities that fall into this category or to pressure test as necessary. Columbia
8 will experience \$1.3 million in incremental O&M annually in order to comply with
9 this federal requirement by outsourcing the majority of this work to contractors.
10 Please see witness Cote's testimony for more details regarding specific pipeline
11 safety requirements resulting from increased federal regulations.

12 Q. Is Columbia proposing an increased incremental O&M expense associated with its
13 public awareness plan obligations?

14 A. Yes it is. In 2011 Columbia experienced 53 occurrences of damage to its system
15 resulting from excavators failing to call 811—the federally mandated Call Before You
16 Dig telephone number. Please see Company witness Cote's testimony for more
17 detail regarding third-party damage, Columbia's number one risk. Columbia is
18 proposing an incremental O&M of \$200,000 annually to increase the advertising
19 and outreach to excavators concerning the need to call 811 before they dig.
20 Company witness Ford (Columbia Statement No. 18) discusses how this increase in
21 RP 1162 funding will support Columbia's RP 1162 communications efforts.

22 Q. You mentioned that Columbia has identified an incremental \$9.25 million of O&M
23 expense associated with the Company's increased level of capital investments and

1 initiatives in 2012 and beyond. Are there any other items that need to be included
2 in the \$9.25 million increase in O&M?

3 A. Yes, there is one more item that is included in the incremental \$9.25 million O&M
4 expense. That expense is an annual incremental \$150,000 needed to hire and train
5 a new employee, as well as to provide training to the current employee in the
6 operation of Columbia's storage facility. Currently, there is only one technical
7 expert who is experienced at operating this facility. Columbia submits that the
8 expense to have a second employee qualified to operate the facility is reasonable
9 and prudent.

10 Q. When will Columbia start incurring the expenses associated with the items making
11 up the \$9.25 million incremental O&M expense you have identified above?

12 A. Columbia is starting to incur many of these expenses now. Specifically, starting in
13 January 2013, Columbia is scheduled to incur incremental O&M on damage
14 prevention enhancements, MAOP Documentation Project, and storage field
15 training. As noted earlier, Columbia started incurring increased O&M with the
16 Alpine Point Operating Center in August of 2012. Columbia will be incurring the
17 full \$9.25 million incremental expense on an annual basis by the end of the Fully
18 Forecasted Future Rate year, or the twelve months ending June 2014.

19 Q. Will you be sponsoring the revenue requirement associated with the \$9.25 million
20 in incremental O&M?

21 A. No. Company witness Gore provides the supporting information related to the
22 revenue requirement. Exhibit RMK-1 includes references to witness Gore's
23 schedules where the rents and leases, labor and benefits, capitalization adjustment,

1 and DIMP expenses can be found.

2 Q. In addition to the O&M expenses associated with DIMP, will the planned volume of
3 capital and O&M work for 2012 and beyond require additional external staffing
4 resources?

5 A. Yes. Based on a comparison to the Company's employee complement as of May 31,
6 2012, and in addition to the 3 GPS mapping technicians described above, we are in
7 the process of hiring 52 field operations and engineering personnel as follows:

- 8 • 14 – Construction Coordinators
- 9 • 4 – Construction Specialists
- 10 • 22 – Construction Operators
- 11 • 3 – Field Engineers
- 12 • 4 – GIS Engineers
- 13 • 3 – Land Agents
- 14 • 1 – Land Tech
- 15 • 1 – System Planner

16 Q. Why does Columbia need to hire these people?

17 A. The biggest driving factor in Columbia's need to hire is its commitment to an
18 increased capital program, and the accelerated replacement of aging infrastructure.
19 In addition, normal attrition, retirements and job progressions into different
20 positions within the Company has caused the Company's work force to drop in the
21 last year. As a result, Columbia is currently in the process of rehiring to fill existing
22 voids and increasing its complement beyond the 2012 historic test year level to
23 address items described in both my testimony and in Witness Cote's testimony.

1 Q. When will these positions be filled?

2 A. These positions are in varying degrees of being filled at the present time. From May
3 31, 2012 to September 6, 2012, we have posted internally or advertised externally
4 for 45 positions, of which 7 of the jobs have been awarded and are in the process of
5 being filled. Because many of these jobs are front line worker positions that are
6 represented by our various unions, we are contractually obligated to offer open
7 positions to existing union members first. As a result, several different internal
8 union movements may take place before we identify an open position that will
9 result in an outside hire.

10 Q. Have all of these positions cited above been included in the claim in this case?

11 A. Yes. Columbia anticipates it may need to fill more positions than have been
12 included in the claim in this case, and will pursue hiring to fill those positions as
13 needed.

14 Q. Does this complete your Prepared Direct Testimony?

15 A. Yes, it does.

Initiative	Total	Leases (A)	Labor & Benefits (B)	Part of Capitalization (C)	DIMP (D)
ROW Clearing	1,000,000			100,000	900,000
Atmospheric Corrosion	1,000,000			100,000	900,000
Exposed Coated CP Pipe Remediation	1,500,000			150,000	1,350,000
Reduced Backlog of Open Type 2 Leaks	2,500,000			500,000	2,000,000
Cross Bore Investigations	1,000,000			100,000	900,000
Alpine Point Operating Center	350,000	350,000		-	-
GPS Mapping Technicians	250,000		250,000	-	-
MAOP Documentation	1,300,000			130,000	1,170,000
Increased RP1162 Expenditures	200,000			-	200,000
Storage Operation & Maintenance	150,000				150,000
	<u>9,250,000</u>	<u>350,000</u>	<u>250,000</u>	<u>1,080,000</u>	<u>7,570,000</u>

***The adjustments reflected above are sponsored by Company witness Gore (Columbia Statement No. 4), and references to witness schedules are provided below.**

(A) Included in Exhibit 104, Schedule 1, Page 2, Line 8

(B) Included in Exhibit 104, Schedule 1, Page 2, Line 1

(C) Included in Exhibit 4, Schedule 2, Page 7, Line 14

(D) Included in Exhibit 104, Schedule 1, Page 2, Line 20

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

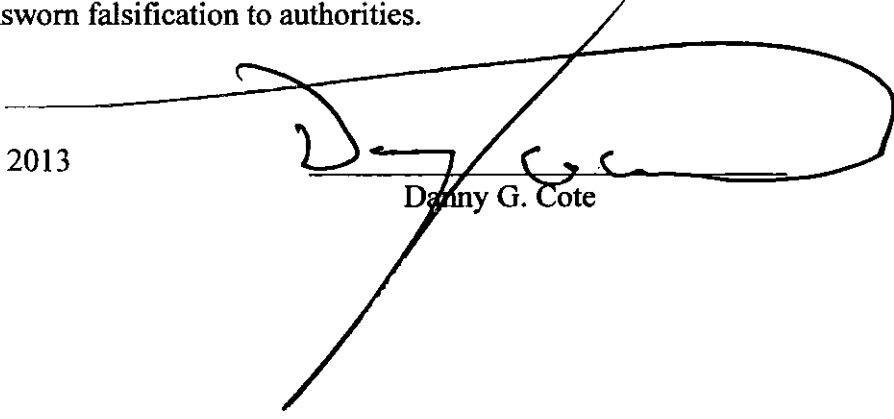
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Danny G. Cote, being Vice President of Pipeline Safety and Compliance of NiSource, Inc. ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 8 and 108-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. DGC-1 and DGC-1R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Danny G. Cote

Pennsylvania Public Utility
Commission

VS.

Columbia Gas of Pennsylvania, Inc.

Docket No. R-2012-2321748

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Danny G. Cote and my Pennsylvania business address is 121 Champion
3 Way, Suite 100, Canonsburg, Pennsylvania.

4 Q. By whom are you employed and in what capacity?

5 A. I am the Vice President of Pipeline Safety and Compliance for the gas distribution
6 segment of NiSource Inc. ("NiSource"), and I am employed by NiSource Corporate
7 Services Company. I assumed this position in May of 2012, and in this capacity I
8 am accountable for all leadership and direction for the newly created Pipeline Safety
9 and Compliance Organization for Columbia Gas of Pennsylvania ("Columbia" or the
10 Company"), Columbia Gas of Massachusetts, Columbia Gas of Maryland, Columbia
11 Gas of Ohio, Columbia Gas of Kentucky, and Columbia Gas of Virginia. The
12 responsibilities related to this position include:

- 13 • Develop the strategic direction and processes for the Distribution and
14 Transmission Integrity Management Programs.
- 15
16 • Develop damage prevention strategies for each business unit, and then
17 support the implementation of those plans at the local level.
- 18
19 • Develop an integrated GPS\GIS mapping and system data capture process
20 for the NiSource natural gas distribution segment.
- 21
22 • Assess and prioritize the physical risks, needs, and opportunities by layer
23 across the NiSource natural gas distribution segment.
- 24
25 • Work with Field Operations and the Regulatory Group to create policies
26 and procedures that clearly define code and NiSource expectations for
27 field execution of operations activities.
- 28
29 • Investigate major issues, events, incidents, that occur in the NiSource
30 natural gas distribution segment.

- Serve as NiSource natural gas distribution segment liaison with state and federal pipeline safety regulators.

Q. Please describe your professional and educational background.

A. I graduated from Edward Little High School in Auburn, Maine, and then attended the University of Southern Maine. I joined the Maine Division of Northern Utilities ("Northern") in 1972 and throughout the 1970's, I held a variety of engineering and operations leadership positions, becoming responsible for Northern's Maine distribution system in 1981. Throughout the 1980's and 1990's, I held a number of operations management roles of increasing responsibility for Northern and Bay State Gas Company ("Bay State") (now d/b/a Columbia Gas of Massachusetts), and from 1995 to 1998 served as Director of Distribution for Bay State and Northern Utilities. Subsequently, I served as General Manager for Bay State's northern region, which includes Bay State's Merrimack Valley service area in Massachusetts, as well as Northern's service areas in Maine and New Hampshire. After that, I served as Vice President of Operations, then General Manager for all of Bay State and Northern. In my most recent prior position, I served as a General Manager of Columbia Gas of Pennsylvania, Columbia Gas of Virginia, and Columbia Gas of Maryland.

Q. Have you previously testified before this or any other regulatory Commission?

A. Yes, I have testified before the Massachusetts Department of Telecommunications & Energy (now the Massachusetts Department of Public Utilities) a number of times in various proceedings. In addition, I have testified before the New Hampshire Public Utilities Commission, the Maine Public Utilities Commission, the

1 Pennsylvania Public Utility Commission, the Maryland Public Service Commission,
2 and the Virginia State Corporation Commission.

3 Q. Please describe your membership in, or affiliation with, any industry organizations.

4 A. My industry affiliations include: Past Chairman of the Board, New England Dig
5 Safe; Past Chairman of the Northeast Gas Association Operations Management
6 Committee; Past Chairman, Northeast Gas Association Operator Qualifications
7 Task Force; Voting member of the American Society Mechanical Engineers B31Q
8 (Operator Qualification) Committee; Past Member, American Gas Association
9 Construction and Maintenance Committee; Member, Society of Gas Operators;
10 Member, New England Guild of Gas Managers, and most recently, a member of the
11 Executive Steering Committee of the Virginia Gas Operators Association. In
12 addition, I have presented numerous papers at industry meetings and seminars on
13 subjects including: Plastic Fusion Qualification Programs, Distribution Integrity
14 Management Programs, Third Party Damage Reduction, Operator Qualification
15 Compliance Strategies, and other Gas Distribution Operations related subjects.

16 Q. What is the purpose of your testimony?

17 A. I describe Columbia's distribution system, its historic operating performance, the
18 initiatives that it has undertaken to improve its overall safety and compliance
19 efforts and the metrics that are use to track performance and progress, including
20 the creation of Columbia's Pipeline Safety and Compliance Organization (the over-
21 sight of which I am now responsible for), new pipeline safety rules, and the planned
22 system enhancements to Columbia's 2012 operations and beyond. I also will discuss
23 Columbia's ongoing replacement activities and provide testimony in support of

1 Columbia's plant additions through the Fully Forecasted Future Rate Year (twelve-
2 months ending June 30, 2014).

3 For the operation and maintenance expense and more specific discussion on
4 operations staffing, please refer to Company witness Kitchell's testimony (Columbia
5 Statement No. 7).

6 Q. Please describe Columbia's distribution system.

7 A. The Company owns and operates a natural gas distribution system and furnishes
8 natural gas service to end use customers. Currently, Columbia serves approximately
9 415,000 residential, commercial, and industrial customers in portions of 26
10 Counties throughout its greater York and Western Pennsylvania service territories.
11 Columbia provides that service through approximately 7,380 miles of mains and
12 approximately 400,000 services that it owns, operates, and maintains.¹ These
13 facilities (as of January 1, 2012) are composed of approximately 1,751 miles of bare
14 steel, 46 miles of cast iron, 113 miles of wrought iron mains, and 66,781 bare steel
15 services.² The balance of the system is comprised of coated cathodically protected
16 steel, or plastic (polyethylene) mains and services, and 81 miles classified as other.³

¹ I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

² The terms "bare steel," "unprotected coated steel" and "unprotected steel," as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

³ It should be noted that in 2011 Columbia deployed a GIS Mapping System (Geographical Information System) to provide both mapping and data retrieval capabilities on its system and facilities. The 81 miles of "other" appear to be anomalies in the data conversion process, and are now being scrubbed to identify and classify the actual pipe in that category. Columbia hopes to have this process completed before the next U.S. Department of Transportation 7100 Annual Report filing in March of 2013)

1 Columbia's distribution infrastructure constitutes the final step in the delivery of
2 natural gas to customers from the producing regions of the Southern United States,
3 Western Canada, and in-state, Pennsylvania-produced supplies. Columbia
4 distributes natural gas by taking it from delivery points (or "city gates") along
5 interstate pipelines, then transporting it through relatively small-diameter
6 distribution mains and services that network underground through cities, towns,
7 and neighborhoods in order to meet the demands of end-use customers. After
8 taking delivery of natural gas at the city gate, Columbia then steps down the
9 transmission pressure to local distribution pressure, further filters the gas to
10 remove moisture and particulates that may damage Columbia's system, and then in
11 some cases increases the amount of odorant known as mercaptan (the "rotten egg
12 smell") to the natural gas before it is put into the distribution system. The gas then
13 goes into the Columbia distribution system where the pressure is often further
14 reduced to delivery pressure in a series of district regulator stations, before being
15 delivered to each customer. Once the gas is delivered on the customer's side of the
16 meter (or the property line in Western Pennsylvania), it is owned by the customer
17 and becomes the responsibility of the customer. In sum, Columbia's distribution
18 system moves relatively small volumes of natural gas at lower pressures over
19 shorter distances to a far greater number of individual users than its interstate
20 pipeline counterparts.

21 Q. Please describe the creation of Columbia's Pipeline Safety and Compliance
22 Organization.

1 A. In early 2012, NiSource determined that it was critical in today's natural gas
2 distribution operating environment to create a department with the specific focus of
3 pipeline safety and compliance. On May 1, 2012, I was named Vice President of
4 NiSource's newly created Pipeline Safety and Compliance Organization.

5 Q. What goals and responsibilities fall under Columbia's Pipeline Safety and
6 Compliance Organization?

7 A. This new department is charged with assessing and prioritizing risks and
8 opportunities, developing state-specific pipeline safety assessments and
9 collaborative strategies, devising strategies to reduce third-party damage, develop
10 standards, interpret state and federal pipeline safety regulations, and work closely
11 with the Columbia operations department overseen by Columbia witness Kitchell to
12 develop processes to ensure compliance, and coordinate with and provide support
13 for Columbia's accelerated infrastructure replacement program. In addition, my
14 department is charged with developing and maintaining relationships with state
15 and federal regulatory agencies, in administering the Transmission Integrity
16 Management Plan, and the new Distribution Integrity Management Program Plan
17 ("DIMP Plan") mandated recently by the United States Department of
18 Transportation's Pipeline and Hazardous Materials Safety Administration
19 ("PHMSA").

20 Q. Why is now the appropriate time to focus on these issues?

21 A. This is not new for Columbia. In my previous role as Columbia's General Manager
22 of Operations, I spent a great deal of time focused on pipeline safety efforts.
23 However, given the recent, high-profile pipeline incidents experienced across our

1 country, and right in our backyard here in Pennsylvania, external expectations at
2 both the federal and state level have demanded more focused attention to pipeline
3 safety and compliance. Specifically, new state and federal regulations, rules,
4 legislation, rulemakings and advisories on pipeline safety are demanding an
5 increased focus across NiSource's gas distribution service territories in
6 Pennsylvania, Maryland, Massachusetts, Virginia, Ohio and Kentucky.

7 Q. Please describe the new pipeline safety rules and advisories that will affect
8 Columbia.

9 A. Some of the more significant and impactful Final Rules that have gone into effect in
10 the last several years or are being considered for the future are as follows:

- 11 • Control Room Management (76 FR 35130) - This rule expedites the program
12 implementation deadlines in the Control Room Management/Human
13 Factors regulations in order to realize the safety benefits sooner than
14 established in the original rule. (This rule requires that Operators define the
15 experience requirements, create training programs, and establish clear roles
16 and responsibilities for Control Room Operators. Further, the rule mandates
17 that appropriate shifts, and maximum hours of work be established for
18 control room operations. The deadline for pipeline operators to implement
19 the procedures for roles and responsibilities, shift change, change
20 management, and operating experience, fatigue mitigation education and
21 training was October 1, 2011, 16 months sooner than the original regulation.
- 22 • Mechanical Fitting Failure Reporting Requirements (76 FR 5494) - This
23 final rule is an amendment to PHMSA's regulations involving DIMP. This

1 final rule revises the pipeline safety regulations to clarify the types of pipeline
2 fittings involved in the compression coupling failure information collection;
3 changes the term "compression coupling" to "mechanical fitting," aligns a
4 threat category with the annual report; and clarifies the Excess Flow Valve
5 (EFV) metric to be reported by operators of gas systems.

- 6 • Integrity Management Program for Gas Distribution Pipelines (74 FR
7 63906) - This final rule amends the Federal Pipeline Safety Regulations to
8 require operators of gas distribution pipelines to develop and implement
9 integrity management ("IM") programs. The IM programs required by this
10 rule are similar to those required for gas transmission pipelines, but tailored
11 to reflect the differences in and among distribution pipelines. In addition to
12 the final rules above, the following are proposed rules that are currently in
13 the PHMSA pipeline:

- 14 • Pipeline Safety: Pipeline Damage Prevention Programs (PHMSA 2009-2192
15 RIN 2137-AE43) - This Advance Notice of Proposed Rulemaking ("ANPRM")
16 seeks to revise the Pipeline Safety Regulations to: establish criteria and
17 procedures for determining the adequacy of state pipeline excavation
18 damage prevention law enforcement programs; establish an administrative
19 process for making adequacy determinations; establish the Federal
20 requirements PHMSA will enforce in states with inadequate excavation
21 damage prevention law enforcement programs; and establish the
22 adjudication process for administrative enforcement proceedings against
23 excavators where Federal authority is exercised.

- 1 • Expanding the Use of Excess Flow Valves in Gas Distribution Systems to
2 Applications Other Than Single-Family Residences (PHMSA 2011-0009 RIN
3 2137-AE71) – The National Transportation Safety Board has made a safety
4 recommendation to PHMSA that excess flow valves be installed in all new
5 and renewed gas service lines, regardless of a customer's classification, when
6 the operating conditions are compatible with readily available valves.
- 7 • Safety of Gas Transmission Pipelines (PHMSA 2011-0023 RIN 2137-AE72)–
8 PHMSA is considering in this advance notice of proposed rulemaking
9 whether changes are needed to the regulations governing the safety of gas
10 transmission pipelines. In particular, PHMSA is considering whether IM
11 requirements should be changed, including adding more prescriptive
12 language in some areas, and whether other issues related to system integrity
13 should be addressed by strengthening or expanding non-IM requirements.
14 Among the specific issues PHMSA is considering concerning IM
15 requirements is whether the definition of a high-consequence area should be
16 revised, and whether additional restrictions should be placed on the use of
17 specific pipeline assessment methods.

18 Q. Please summarize the results of your assessment of Columbia's pipeline safety risks
19 and opportunities.

20 A. As I noted earlier in my testimony, my organization is affording Columbia the
21 capability to focus more attention to pipeline safety and compliance efforts than it
22 has previously devoted in prior years. In collaborating with witness Kitchell, we
23 have identified the following system enhancements for 2013 Columbia Gas of

1 Pennsylvania operations: to accelerate the repair rate of open Type-2 leaks, to bring
2 all locating work back in-house in order to reduce third party damage, to increase
3 the use of camera-based technology to identify cross-bore conflicts, to deploy GPS
4 technology to identify the location of all new facilities, and to enhance damage
5 prevention advertising and contractor outreach.

6 The pipeline safety action enhancement agenda identified above, in conjunction
7 with our ongoing bare steel, cast iron, and wrought iron accelerated replacement
8 program, is designed to address the key risks identified in Columbia's Distribution
9 DIMP, and continue to reduce the pipeline safety risks inherent in the Columbia
10 Gas of Pennsylvania system.

11 Q. Regarding Columbia's operating performance, does the Company meet or exceed
12 state and federal requirements for leak surveying?

13 A. Yes, in 2007 Columbia began an accelerated leakage survey program to inspect all
14 bare steel mains annually, instead of the three year interval which is required in the
15 leakage survey requirements of CFR 49, Part 192. The result of this is that Columbia
16 routinely exceeds the requirements of existing Code of Federal Regulations, and
17 provides the Company the ability to discover system leakage on a much timelier
18 basis than if it were only meeting the minimum federal standards. In addition, as a
19 result of the Commission's Tentative Order regarding Natural Gas Pipeline
20 Replacement and Performance Plans, at Docket No. M-2011-2271982, Columbia
21 agreed to perform a second annual business district survey for the 2011-2012 winter
22 heating season.

23 Q. How does Columbia classify leaks it detects on its system?

1 A. Columbia classifies each gas leak according to its severity: Type-1, Type-2, or Type-
2 3. A Type-1 leak is hazardous and requires immediate remediation and repair. A
3 Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled
4 repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as
5 “non-hazardous at the time of detection and can be reasonably expected to remain
6 non-hazardous.”

7 These gas leak classifications are defined in the Gas Piping Technology Committee
8 (“GPTC”) ANSI Z380.1 “Guide for Gas Transmission and Distribution Piping
9 Systems.” The Guide is commonly utilized by gas operators and State pipeline
10 regulators, including the Commonwealth of Pennsylvania, as an interpretation of
11 “DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By
12 Pipeline: Minimum Federal Safety Standards.”

13 Q. What are some of the other ways that Columbia has improved its system
14 operations?

15 A. Beginning in 2006, Columbia launched a number of specific initiatives to improve
16 its operating performance, and the operating characteristics of its system. Further,
17 these improvements dovetail precisely with, and are a continuation of, Columbia’s
18 ongoing DIMP Plan.

19 Some of these DIMP driven practice enhancements or procedure changes include:

- 20 • Reduce the number of open Type-2 leaks in the Columbia distribution
21 system as measured by the annual Federal DOT report. It is worthy of noting
22 that corrosion on bare steel is the second most serious DIMP Plan risk in the
23 Columbia system, and that roughly 85% of the Type-2 leaks in the system are

1 caused by corrosion on bare steel. Further, this is a significant undertaking
2 in assuring safe and reliable service to customers, as the greater the number
3 of leaks in a system and the longer they are left unattended, the greater the
4 potential risk of gas migrating into a structure or other underground facility.

5 The result was that the end of 2007 (the first full year of Columbia's annual
6 system wide bare steel survey), Columbia reported a total of 3,755 open
7 Type-2 leaks in its Distribution System. As of August 1, 2012 Columbia had
8 2,035 open Type-2 leaks, which equates to a nearly 45% reduction in the last
9 5 years. In addition, as indicated in our DIMP Plan initiatives for 2013 and
10 beyond, Columbia intends to continue to accelerate its Type-2 leak repairs in
11 order to further reduce the backlog of open Type-2 leaks.

- 12 • Improve Columbia's locating performance and excavator outreach as
13 measured by Third Party Damage per thousand locates. This operational
14 safety metric is particularly critical as third party damage is the leading cause
15 of federally reportable pipeline incidents [e.g. Death, Injury requiring
16 hospitalization, or Property Damage over \$50,000] in the United States. In
17 addition, it is the top risk identified in Columbia's DIMP Plan. Since 2006,
18 Columbia has undertaken a comprehensive process designed to improve
19 locating performance and reduce third-party damage to Company facilities.
20 This process has included tighter management and more stringent
21 performance standards for locators, and resulted in a pilot program initiated
22 in 2009 to bring the locating function back in-house for two large operating
23 centers in Pennsylvania. In early 2012, Columbia decided to bring all

1 locating back in-house for all of its locations. The Company made this
2 decision because the data from the pilot program consistently showed that
3 in-house locators delivered better third party damage results than those of
4 any of the contract locators who had performed this work over the last 5
5 years.

6 Further, Columbia routinely conducts face-to-face meetings with excavators
7 who are frequent damagers, to train their employees in safe excavating
8 practices, as well to remind them of the potential consequences of damaging
9 natural gas facilities. These efforts have resulted in a 57% reduction in third
10 party damage on the Columbia system between 2006 and 2012, from a
11 damage per thousand (locate requests) rate of 5.47 in 2006 to a damage per
12 thousand rate of 2.34 through July of 2012. This constitutes the lowest
13 damage rate that Columbia has experienced through this point of the year
14 since we have been tracking this data.

15 Q. What kinds of pipe have historically been installed in Columbia's system?

16 A. The system comprises many different types of pipe. From the 1850s to the early
17 1900s, Columbia's predecessor companies installed cast iron pipe throughout the
18 early distribution systems. Cast iron, wrought iron and wood were among the first
19 materials available, and cast iron had the advantage in that it was relatively strong
20 and was easy to install. However, it was vulnerable to breakage from ground
21 movement. When the pipe was buried to typical depths of between two and five
22 feet, if the soil beneath the pipe or to its side was disturbed and pressure exerted on
23 the pipe, it could crack. Further, each pipe section was not easily joined, so joints

1 were prone to leaks. Finally, it was determined that it was unsuitable for long-
2 distance transportation of gas because it was unable to withstand high pressures.

3 Q. How did the industry react to the problems present with the use of cast iron?

4 A. By the early 1900s, the industry had adopted steel and wrought iron piping for
5 mains. These were deemed to be stronger than cast iron and able to withstand
6 greater pressure. During this time, bare steel and wrought iron began replacing
7 cast iron pipe as the material of choice when building a natural gas distribution
8 system. During the pre and post-World War II construction boom, gas utilities like
9 Columbia, along with developers and customers, installed a significant amount of
10 bare steel mains and services. Bare steel is steel pipe that has no exterior coating
11 and has no cathodic protection installed on the pipe. The use of bare steel and
12 wrought iron was common until the 1950s and 1960s when the industry began to
13 realize that, despite its strength, bare steel was subject to corrosion and, in order to
14 increase long-term safety and reliability, coating and cathodic protection should be
15 applied to all new piping systems. Both exterior coatings and cathodic protection
16 were designed to inhibit corrosion. Columbia installed its last bare steel pipe in the
17 1960s. By 1970, the federal government prohibited the use of bare steel for natural
18 gas distribution system infrastructure.

19 Q. What did the industry do to combat the problem of corrosion in bare steel?

20 A. The fact is that all metals corrode as a result of the natural process of chemical
21 interactions with their physical environment, most commonly caused by moist soil
22 (which creates an electrolyte) around the pipe, causing corrosion. In these
23 circumstances, direct electric current flows from the metal surface into the

1 electrolyte and, as the metal ions leave the surface of the pipe, corrosion takes place.

2 This current flows in the electrolyte to the site where oxygen or water is being
3 reduced. This site is referred to as the cathode or cathodic site. In order to combat
4 corrosion, LDCs began using coated steel. Unprotected coated steel ("UPCS" or
5 "coated steel") refers to steel pipe with an exterior coating (intended to electrically
6 isolate the steel from the surrounding electrolytes in the soil).

7 Q. Did the use of UPCS solve the problem?

8 A. No, despite the best efforts of industry, and even though it was for a time an
9 accepted industry standard, unprotected coated steel corroded as well. But for the
10 period from the 1940s through the 1960s, as the industry assessed its options, it was
11 one of just a few alternative piping materials available to meet the public demand
12 for service. By 1970, Columbia had laid its last non-cathodically protected coated
13 steel segment. Further, since that time Columbia has retrofitted all of its
14 unprotected coated steel facilities with cathodic protection systems.

15 Q. What materials replaced bare steel and coated steel?

16 A. Coated steel pipe continues to be used, but it is cathodically protected with an
17 electric current. The pipe breakthrough for the Natural Gas Industry came in the
18 mid-1960s with the introduction of plastic (polyethylene) pipe for gas distribution
19 applications.

20 Q. What is "cathodic protection?"

21 A. Cathodic protection is a procedure by which underground metal pipe is protected
22 against corrosion and deterioration (i.e. rusting and pitting) by applying an
23 electrical current to the pipe. Cathodic protection reduces corrosion by making that

1 surface the cathode and another metal the anode of an electrochemical cell. A
2 primary function of a coating on a cathodically protected pipe is to reduce the
3 surface area of exposed metal on the pipeline, thereby reducing the current
4 necessary to cathodically protect the metal. At present, the principal methods for
5 mitigating corrosion on underground steel pipelines are external coatings and
6 cathodic protection.

7 Q. Has Columbia further improved the functionality of its piping since the
8 introduction of cathodically protected steel?

9 A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of
10 strength and, because of its impressed electrical current, is highly corrosion
11 resistant. However, it is more costly to purchase and install, and requires more
12 ongoing maintenance than the next generation pipe – plastic.

13 Q. What are the benefits of plastic pipe?

14 A. Plastic pipe has proven to be very good for distribution-level pressures. It has
15 strength and flexibility, and, as a result, is generally immune to the stress of ground
16 movement. Plastic is also less costly to purchase and easier to join and install than
17 steel pipe. Plastic does not corrode and, therefore, does not require cathodic
18 protection.

19 Q. Does plastic pipe have any drawbacks?

20 A. The single significant drawback to plastic is its relative vulnerability to third party
21 damage compared to cast iron or steel. As a result, excavators who do not dig by
22 hand (as required by One-Call laws) in the vicinity of plastic facilities are very likely
23 to damage them. Cast iron and steel piping have greater tensile strength and thus

1 are somewhat more likely to be able to resist external impact.

2 Q. What is Columbia doing to address this concern?

3 A. As I explain elsewhere in my testimony, we have improved Columbia's locating
4 performance and excavator outreach to reduce risks to the system caused by
5 excavator damage. In addition, under my direction Columbia has begun using
6 "marker balls" when installing its new plastic facilities. These marker balls are
7 placed in the ground above the pipe after it has been installed and enable Columbia
8 to locate it later using electronic technology. Further, in late 2012 Columbia will be
9 partnering with the Gas Technology Institute to test the newly developed GPS/bar-
10 coding facilities identification solution that will provide sub-decimeter accuracy in
11 identifying the location of new or replacement facilities. If this technology proves to
12 be successful, it will provide Columbia with a breakthrough technology in its ability
13 to accurately identify all of the components that it has in the field, and physically
14 locate them to within 3 inches in the field. In addition, this will provide locators
15 with a highly accurate, state-of-the-art ability to find facilities anywhere in the
16 system that have been captured using this new technology.

17 Q. How does Columbia install pipe in its underground distribution system?

18 A. The initial installation of natural gas distribution pipe requires the excavation of a
19 trench usually under or adjacent to a public street into which the pipe is laid. Then
20 new or existing customer services are connected to the new main.

21 Installation of natural gas distribution pipe can be a major inconvenience for
22 residents, business owners and municipalities. In some circumstances, where
23 smaller diameter plastic facilities are installed to replace larger diameter steel

1 piping, the cost and inconvenience associated with excavating a trench can be
2 reduced by inserting the new pipe through the old piping. This involves smaller
3 street cuts for the insertion plus cuts associated with service line and intersecting
4 main tie-ins. Even if a replacement main must be laid rather than inserted, the use
5 of smaller plastic pipe rather than larger steel or cast iron pipe will produce a
6 savings in material costs.

7 Q. During the last five years, how much bare steel and cast iron main has been
8 eliminated from the Columbia system? How does that trend compare with the
9 previous four years?

10 A. In 2007, Columbia began to accelerate the replacement rate of bare steel and cast
11 iron pipe. Between 2007 and 2014 Columbia has retired, or projects to retire, the
12 following footages of bare steel or cast iron by year:

13	2007	355,764 feet
14	2008	528,567 feet
15	2009	344,488 feet
16	2010	322,583 feet
17	2011	533,765 feet
18	2012	540,000 feet Projected
19	2013	550,000 feet Projected
20	<u>2014</u>	<u>550,000 feet Projected</u>

21 **Total (Through 2012) 2,625,364 feet**

22 By contrast, between 2002 and 2005 Columbia retired the following footages of
23 bare steel or cast iron by year:

1	2002	232,320 feet ⁴
2	2003	179,520 feet
3	2004	201,712 feet
4	<u>2005</u>	<u>174,240 feet</u>
5	4 Year Total	787,792 feet

6 This underscores the scope of our accelerated replacement program as over the last
7 6 years (including 2012) we will have eliminated an average of 437,560 feet per
8 year, compared to an average annual rate of 196,948 feet in the 4 years from 2002
9 to 2005. This constitutes an increase in the annual retirement rate by a factor of
10 2.23 times that of the earlier period.

11 Q. Why does Columbia need to continue to replace its bare steel and cast iron systems?

12 A. In recent years, Columbia has determined that there are an increasing number of
13 leaks in areas where unprotected steel is concentrated. Thus, it is imperative that
14 Columbia continue to replace its first generation system aggressively to off-set the
15 accelerating leak rate. In fact, corrosion on these first generation mains and
16 services represents over 85% of all the Type-2 leakage (and a significant portion of
17 the Type-1 leaks) that occurs annually on mains in the Columbia distribution
18 system. To state this another way, bare steel and cast iron mains are at least 16
19 times more likely to experience leakage than plastic or cathodically protected
20 facilities. As a result of this clear trend, Columbia continues to believe that it needs

⁴ This is based on using the 2000 bare steel and cast iron footage rather than the 2001 footages, as in 2001 the DOT reports actually show an increase in the amount of bare steel and cast iron in the system. Since bare steel and cast iron pipe was not added to the system, we believe this is an anomaly in the data.

to replace the bare steel and cast iron system more rapidly than it did prior to 2007. Further, Columbia plans to increase its capital expenditures in 2013 and 2014, with \$141 million budgeted for the bare steel and cast iron replacement program in 2013, and \$138 million in 2014. Based on these expenditures, Columbia will eliminate 550,000 feet of bare steel and cast iron in 2013, and 550,000 feet in 2014. For additional information and detail on the 2013 & 2014 capital expenditures for Columbia's system replacement program, please see the figure below.

CPA Age & Condition Replacement Budgets (\$000)

Gen	Description	2011 Budget	2012 Budget	2013 Projected (1)	2014 Projected (1)
Replacement - Age & Condition					
355	Measuring and Regulating Station				
354	Compressor Stations	0	1,050	1,000	1,000
Various	Acquisition or Sale of Gas Plant in Serv				
376	Mains - Leakage Elimination	63,400	80,052	99,220	96,520
380	Service Lines - Replace	19,500	30,500	36,530	36,230
381	Meters - Replace	900	750	1,000	1,000
382	Meter Installation - Replace	1,000	1,100	1,300	1,300
383	Regulators - House - Replace	150	250	400	400
378	Regulators - Plant - Replace	550	700	750	750
375	Regulator Structures - Replace	150	200	200	200
385	Large Vol/XS Press Meas Station - Replace	150	200	400	400
376	Corrosion Mitigation Installation	200	200	200	200
383	Service Regulators - Replacement				
381	Interco Transfer - CDC				
Total Replacement - Age & Condition		86,000	115,000	141,000	138,000

(1) It should be noted that actual capital budgets for the following year have previously been approved in the fourth quarter of the current year. In light of the Fully Forecasted Future Rate Year provided by Act 11 of 2012, CPA's capital budget has been approved through the end of 2014.

Taken in total, Columbia has made enormous progress since 2006 in delivering and maintaining a safe and reliable distribution system for its customers. The progress that I refer to is defined in more detail earlier in this testimony, but includes initiating an annual leakage survey on all of its bare steel mains, reducing the

1 number of inactive services in the system, reducing its Type-2 leak repair backlog,
2 improving the locating process to reduce third party damage, improving emergency
3 response rates and on-time appointments for customers, and dramatically
4 increasing the amount of bare steel and cast iron pipe that it removes from the
5 system annually. Having said all of that however, the system data is clear that as
6 first generation bare steel and cast iron pipe continues to age, Columbia will have to
7 continue to focus on the accelerated replacement of bare steel and cast iron to
8 address the problems associated with aging infrastructure. Therefore, it is essential
9 that Columbia continue to direct management effort and incremental capital
10 resources toward this ongoing need. The synchronization of these replacement
11 efforts with the enhanced focus on pipeline safety that Columbia has demonstrated
12 over the last 6 years are integral parts of Columbia's DIMP Plan, and are essential
13 planks of Columbia's ongoing efforts to enhance natural gas pipeline integrity
14 management, and thus provide a safe, reliable distribution system for our
15 customers, and the general public.

16 Q. How do Columbia's bare steel replacement rates compare with other Pennsylvania
17 Local Distribution Companies ("LDCs")?

18 A. An analytical comparison of the following PA LDCs 7100 DOT reports for changes
19 in the amount of bare steel pipe in the systems during the years of 2009, 2010 and
20 2011 show the following (in miles):

21

22

23

LDC Bare Steel Main Replacements\Retirements by Company

Bare Steel (miles) from 7100 DOT reports

	Peoples	Equitable	UGI	PECO	Columbia
2009	1,917	781	391	367	1,958
2010	1,906	762	379	361	1,902
2011	1,884	737	368	355	1,751
Change in 2010	11	19	12	6	56
Change in 2011	22	25	11	6	151

As this chart demonstrates, in the last three years for which there is data, Columbia has replaced more than four and one-half times as much bare steel main as the next highest LDC among its peers in Pennsylvania.

Q. Is there another solution for addressing the issues with bare steel and cast iron short of replacement?

A. No. Corrosion leakage on unprotected steel does not slow down and the rate of leakage will only accelerate as the unprotected steel facilities continue to deteriorate. First generation unprotected steel pipe, much of it dating to the turn of the last century, has reached or soon will reach the end of its useful life and must be replaced in a timely, cost-effective manner.

Q. Do system operations requirements demand replacement of Columbia's unprotected steel facilities?

A. Yes. Continual system degradation due to unrelenting corrosion will challenge Columbia's ability to meet peak day needs and operate the system safely. Therefore,

1 continuation of Columbia's main replacement program is an essential alternative to
2 a high leakage rate and the associated public risks and additional strain on the
3 system when required to meet peak day demands on the system.

4 Q. Could the accelerating leak problem potentially increase the risk to public safety?

5 A. Yes. Every corrosion leak has the potential to become a risk to public safety.
6 Because bare steel corrosion leakage will accelerate over time, the more frequent
7 leakage will result in greater risk that a significant event will occur.

8 Q. Are you saying Columbia's system is unsafe?

9 A. No, I am saying the system is safe right now, as evidenced by our ability to address
10 Type-1 and Type-2 leaks appropriately, as well as all of the other operational
11 improvements including more frequent leakage surveys that are described earlier in
12 this testimony, and better emergency leak response that are described in witness
13 Kitchell's testimony. The "system" is comprised of thousands of miles of wrought
14 iron, cast iron, bare steel, cathodically-protected steel, and plastic pipe. The
15 material initially at risk is first generation bare steel. Evidence further indicates that
16 the corrosion with respect to unprotected coated steel is accelerating, gradually
17 causing more leaks. Cast iron pipe also is quite old and is in need of replacement
18 due to its age and vulnerability to fractures caused by ground movement. While the
19 system is currently safe, Columbia must, as a prudent operator, address the
20 systemic problem of replacing its unprotected steel facilities.

21 Q. Will Columbia's accelerated replacement program provide customers with any
22 other benefits besides the replacement of bare steel and cast iron pipe with plastic
23 and cathodically protected steel?

1 A. Yes. Columbia is replacing the segmented, 19th and early 20th century low-
2 pressure designs of its first generation system with a more integrated, 21st century
3 system design. This integrated, higher pressure (up to a maximum of 99 pounds)
4 system will enable Columbia to substantially reduce the current need for district
5 pressure regulator stations throughout its system, thereby making the system safer,
6 easier and more reliable to operate (instead, each residence has a small domestic
7 sized regulator installed just up-stream of the meter to reduce the pressure before it
8 enters the house). A distribution system operating at these higher pressures also
9 will enable Columbia to install new safety devices in areas to be upgraded. As part
10 of the upgrade, Columbia is installing excess flow valves on nearly all services
11 connected to the replacement mains. (The exception would be for those
12 commercial and industrial customers whose consumption is over 5,000 CFH per
13 hour.) For approximately \$25 per replacement residential service, or less than \$50
14 for the average commercial service, these excess flow valves will shut off gas to a
15 residence or business in the event of a large pressure differential, indicative of a
16 major gas leak, or a service damaged by excavation. This results over time in a
17 system where services are much less vulnerable to safety risks from third-party
18 damage.

19 Q. How will main replacements affect the Company's leak repair experience?

20 A. Given the acceleration of corrosion-related leaks that I described previously, and
21 the realization that 85% of the Company's current main leakage is corrosion related,
22 over the next few years Columbia's program will only slow or possibly halt the
3 growth in main corrosion leak repair-related operations and maintenance expenses.

1 As a result of this phenomenon, Columbia is unlikely to see a reduction in O&M
2 leak repair costs for a number of years. Based on Columbia's DIMP driven initiative
3 to further reduce the back-log of Type-2 leaks, in the short and medium term, O&M
4 spending on leak repairs are planned to increase. That said, in the longer term, as
5 the percentage of bare steel and case iron pipe is materially diminished we would
6 expect to see a reduction in such expenses.

7 Q. What benefits inure to the public from Columbia's ongoing replacement of its aging
8 facilities?

9 A. Columbia is removing deteriorating portions of its system and enhancing the safety
10 of its system by ensuring replacement of facilities with new, longer lasting and safer
11 materials. Its system will continue to be able to provide deliverability at its MAOP.
12 The public will receive better service, with fewer interruptions. Further, this
13 massive and structural system replacement program is adding jobs throughout
14 Columbia's service territory, both in the ranks of regular Columbia employees
15 (these include engineers and engineering techs, land agents, and construction
16 inspectors), as well as the Contractors who perform the actual pipe replacement
17 (which includes laborers, equipment operators, crew leaders, and support staff)
18 which will be further discussed in Witness Kitchell's testimony.

19 Q. Please summarize the cost benefits of Columbia's bare steel replacement program.

20 A. By employing a systematic approach to replacement that integrates Columbia's
21 program work with State and municipal improvements, costs are minimized.
22 Columbia is able, through competitive bidding, to continue to secure long-term,
23 lower unit cost contracts with various utility installation contractors. Columbia is

1 also able to purchase larger quantities of construction materials by competitive
2 bidding, resulting in lower cost, long-term contracts. By these means, I expect
3 Columbia will have substantially lower capital costs as the program continues to
4 expand. That notwithstanding, over the long term the one significant challenge
5 from an operations perspective that exists to Columbia's ability both to perform
6 system maintenance and to replace facilities in a cost effective manner, is the
7 recent trend we are seeing from some municipalities to enact very costly
8 excavation permit fees and extensive restoration requirements. While Columbia
9 has been vigilant in trying to negotiate the fees and requirements to reasonable
10 levels, there is not sufficient statewide legislation to support this effort in a
11 systemic way. Permit fees and restoration requirements can be seen as a source
12 of easy revenue for some municipalities and can create a burden on all rate
13 payers through rising construction costs. Replacing aging facilities in
14 coordination with planned municipal paving projects is one way Columbia is
15 attempting to manage these rising costs.

16 Q. Please explain Columbia's capital additions claimed for the Test Year.

17 A. The capital expenditures for the Future Test Year ended May 31, 2013 and the Fully
18 Forecasted Rate Year ended June 31, 2014 are shown in Exhibit 108, Schedule 1.
19 The amounts shown are taken from Columbia's capital budget, as developed by our
20 operations group and engineering department. That said, the 2012-14 capital plan
21 includes the replacement of 540,000 feet of bare steel and cast iron main in 2012,
22 and 550,000 of bare steel and cast iron in 2013 and 2014. For a listing of large
23 replacement projects being constructed in 2012, and those planned for 2013 and

1 2014, please see Exhibit DGC - 1.

2 Q. Will the planned volume of capital and O&M work for 2012 and beyond require
3 hiring any additional external staffing resources?

4 A. Yes, please see Witness Kitchell's testimony for discussion of O&M costs associated
5 with the increased level of O&M spending necessitated by Columbia's DIMP plan,
6 and the additional Capital manpower required to execute Columbia's infrastructure
7 replacement program.

8 Q. Does this complete your Prepared Direct Testimony?

9 A. Yes, it does.

CPA - 2012 Infrastructure Project Replacement Summary

9/20/2012

Project Name	Pipe Size	Install Footage
D-1581 Country Club Drive Area	16"	3,125
Fairland Phase II	2" - 6"	4,000
Pickwick Area - Bethel Park	2' - 6"	3,000
College and Lincoln	4" & 6"	8,700
D-4 Phase II	4" & 8'	9,000
D-1 Phase I	16"	1,300
Winshire Area - Pittsburgh North Side AMRP Phase II	2" & 4"	3,600
D-82 Cranberry Township	8"	20,000
Kenyon Avenue Area	2" - 6"	4,400
Delaware Avenue Phase II	2" & 4"	7,500
Willowbrook Road	2" - 6"	8,800
D-5181 Allegheny River Crossing	6"	1,200
Emlenton AMRP	2" - 6"	6,000
D-8500 Duck Hollow	10"	3,500
Cedar St, Jeannette	4 & 2"	12,000
D-1254, Somerset	8"	10,340
Edgewood Rd, York	12"	4,000
E. Princess St, York	4 & 2"	12,639
N. Main/Susquehanna Trail	6"	3,500
Tri-Hill, York	8"	4,100
S. Main/Sunset, Shrewsbury	8"	5,800
E Main, Dallastown	8"	6,000

CPA - 2013 - 2014 Infrastructure Project Replacement Summary

9/20/2012

Project Name	Pipe Size	Install Footage
VaniKirk	4"	2,200
Kirsopp	6"	3,000
Ehle	4"	4,000
Freeland	4", 2"	2,400
Gearing	2"	1,850
Lodge	4", 2"	1,200
Broadmoor Avenue	4", 2"	4,000
Iroquois Drive	4"	5,400
Fruitthurst Drive	4", 2"	4,600
Cliff Mine Road	2"	2,100
Glencoe	4"	1,250
Orchard/Parkway	2"	3,400
Fairland Phase III	4", 2"	9,200
Tropical/Crane	4", 2"	8,500
D-1581	8"	4,000
D-10183	6"	10,000
Lincoln Avenue in McDonald	4"	1,200
Wolfsdale	6", 4", 2"	5,000
Caldwell Avenue	8"-4"	9,000
Franklin Avenue	4"	1,500
Bucktown	2", 4"	8,400
Dutch Hill	2", 4"	4,800
East National Parkway	2", 4"	6,200
Shenango Road - Active Corrosion	2 & 4	3,100
Wittmer Street	2 - 6	1,160
4th Street - Active Corrosion	4	1,120
Ambridge Avenue - Active Corrosion	4	2,530
D-74 - Coraopolis	8	5,200
D-84 - Monaca	10	1,200
Sewickley Cast Iron - AMRP	2 - 6	3,960
D-88 River Crossing	8	1,200
D-1 Phase II at Groveton	16	2,800
Ray Street	4	3,800
Pershing Street	4	5,200
Emmerton MP Phase II	2 & 4	3,400
D-5181 Pickard Valley	6	4,500

Project Name	Pipe Size	Install Footage
D-4227 Phase I	8	3,800
Pleasant Drive	2 & 4	2,500
D-1254 Lichty School Rd	8"	5,200
Franklin, Somerset AMRP	2 1/4"	9,000
D-7024 Gregg Dr	8"	2,500
D-7128 Craftmore Rd	8"	4,970
Cedar St AMRP	2 1/4"	12,200
Water Street, California AMRP	2"	3,700
Ridge Av. (Juergens)	12"	3,700
Penn St. (Juergens)	6" & 8"	15,000
Company St. (Juergens)	4" & 2"	2,800
Sycamore Rd (Wagaman)	6 & 2	2665 & 1000
11th Ave (Wagaman)	6 & 2	3763 & 4016
Bridgeton Rd (Wagaman)	6	2,195
Lincoln Avenue (Martin)	6-8	3,100
Gottysburg Crossing HP (Martin)	8	3,420
College Ave AMRP (Clark / Gill)	4 & 2	3,580
West Jackson Street (Clark)	4 & 2	13,347

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, John E. Skirtich, being a consultant specializing in utility regulation, hereby state that the testimony set forth in Columbia Statement Nos. 9 and 109-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. JES-1 through JES-5 and JES-1R through JES-8R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


John E. Skirtich

2-13-13

Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

Vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
JOHN E. SKIRTICH
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

SEPTEMBER 28, 2012

1 Q. Please state your name and business address.

2 A. My name is John E. Skirtich. My business address is 279 Old Trail Drive,
3 Columbus, Ohio 43213

4 Q. What is your current occupation?

5 A. I am a consultant specializing in utility regulation.

6 Q. For whom are you testifying today?

7 A. I am submitting testimony on behalf of Columbia Gas of Pennsylvania, Inc.
8 ("Columbia").

9 Q. Please describe your professional experience.

10 A. Upon graduation in 1970, I worked for R. A. Saunders and Co., a CPA firm in
11 Columbus, Ohio as an accountant. In November 1970, I was hired by the Columbia
12 Gas System Service Corporation, a subsidiary of the Columbia Gas System, Inc.
13 subsequently Columbia Energy Group where, during the course of my nearly 30
14 years of employment, I held a number of financial related positions with the last 18
15 years in the regulatory function.

16 In June 2000, I retired from Columbia Energy Group, and in December
17 2000, I began providing regulatory consulting services for several distribution
18 companies of NiSource Inc. From June 2001 through November 30, 2009, I
19 provided regulatory consulting services through employment agencies and then
20 starting December 1, 2009 as an independent contractor.

21 Q. Please describe your educational background.

1 A. I graduated from Capital University, Columbus, Ohio, in 1970, with a Bachelor of
2 Science degree in Business Administration.

3 Q. Have you ever testified before the Pennsylvania Public Utility Commission
4 ("Commission") or any other regulatory commission?

5 A. Yes I have. I have testified before the Pennsylvania Public Utility Commission
6 ("Commission"). In addition, my testimony has been accepted by the Kentucky
7 Public Service Commission, the Massachusetts Department of Public Utilities, the
8 Maryland Public Service Commission, the New Hampshire Public Utilities
9 Commission, the Public Utilities Commission of Ohio, and the Virginia State
10 Corporation Commission.

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

12 A. As required by Section 53.53 III, Items 1 and 9, I prepared Allocated Cost of
13 Service Studies by rate class at present and proposed rates (Item 1) and a cost
14 analysis supporting minimum charges for all rate schedules (Item 9). The studies
15 and cost analysis are presented in Exhibit 111. Item 10 of Section 53.53 III,
16 requires a cost analysis supporting demand charges. None was prepared since
17 Columbia's present and proposed tariffs do not contain distribution demand
18 charges.

19 Q. Please describe Exhibit No. 11.

20 A. Exhibit No. 11 addresses the Commission's filing requirements regarding
21 Allocated Cost of Service ("ACOS") studies and rate design as required by Section

53.53 III. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the methodologies are included in Statement No. 9. The ACOS studies are based on the fully forecasted test year ending June 30, 2014.

Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?

A. Yes, I am.

Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?

A. Yes.

Q. Why did you conduct three ACOS studies?

A. Columbia has filed two studies since the early eighties that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class while the peak & average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia recognizes that no one cost of service study is the "right" study and in the past believed the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates.

Q. What is the basis of the third study and why did Columbia file it?

A. The third study as presented in Exhibit No. 111, Schedule 3 is an average of the customer-demand study and the peak and average study. Columbia continues to believe that the customer-demand study and the peak and average study provide a reasonable range, and the average study with its equal weighting of the two

provides the Company, the parties, and the Commission a set of returns that can be used as a benchmark or guide in revenue allocation. It is another tool that is used in setting rates based on the cost to serve.

Q. Could you provide a list of the schedules and exhibits you are sponsoring through your testimony?

A. Yes. For clarity purposes, the table below lists all the schedules and exhibits that I am sponsoring.

<u>Schedule/Exhibit</u>	<u>Description</u>
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak & Average Study
Exh. No. 111, Schedule No. 3	Average Study
Exh. No. 111, Schedule No. 4	List of Allocation Factors
Statement No. 9, Exhibit JES-1	Results Summary - Rates of Return by Rate Schedule
Statement No. 9, Exhibit JES-2	Development of Allocation Factors
Statement No. 9, Exhibit JES-3	Development of Allocation Factors Factor Nos. 5, 20 and 22
Statement No. 9, Exhibit JES-4	Factor Selection and Rationale
Statement No. 9, Exhibit JES-5	Revenue Change at System Average for LDS

Q. Could you briefly describe the format of the ACOS studies that you are sponsoring?

A. The format is generally identical for the three studies except for the customer-demand study, schedule No. 1. It contains 18 pages while the peak and average

1 study in schedule 2 and the average study in schedule 3 contain 13 pages. Pages 14
2 through 18 of the customer-demand study contain the system charge studies, which
3 I will be discussing later in my testimony. The rates of return that are shown on
4 page 1 of the studies are based on income generated using proposed rates with page
5 2 showing the rates of return generated using current rates. Both page 1 and page 2
6 summarize the same allocated cost of service with the exception of income taxes
7 and uncollectibles which vary with the changes in revenue as a result of the change
8 in current rates to proposed rates. The allocation of gross plant investment is
9 shown on page 3 while page 4 contains the reserve for depreciation and page 5
10 depreciation and amortization expenses. Revenue by account and rate schedule is
11 summarized on page 6 for both current rates and proposed and pages 7 and 8
12 contain the allocation for operation and maintenance expenses and page 9 taxes
13 other than income. Rate base is detailed by rate schedule on page 10 with page 11
14 calculating Federal and Corporate Net Income taxes. The allocation factors are
15 listed on pages 12 and 13. As noted above, a summary of the rates of return by rate
16 schedule is provided in Exhibit JES-1.

17 Q. How were the rate schedules grouped in allocating the cost of service?

18 A. For residential and small general service, sales and delivery services were
19 combined, respectively; Residential Sales Service ("RS") and Residential
20 Distribution Service ("RDS") were combined and presented in Column D of each
21 study, and Small General Sales Service ("SGS"), Small Commercial Distribution

1 and Small General Distribution Service ("SGDS") were combined and presented
2 in Column E of each study. Since essentially any customer can qualify, and
3 therefore, switch between sales and distribution services under these schedules,
4 it is reasonable to conclude that customer characteristics are the same for both
5 types of services, i.e., size, consumption patterns, heat sensitive, human need
6 requirement, etc. With no long term difference in the customers' profiles, the
7 distribution cost to provide such service is equivalent. For the larger customers,
8 the study presents the cost of service for each rate schedule: Large General Sales
9 Service ("LGS") is presented in Column F, Small Distribution Service ("SDS") is
10 presented in Column G, and Large Distribution Service ("LDS") is Column H.
11 Main Line Sales Service ("MLS") and Main Line Distribution Service ("MDS") are
12 combined and presented in Column I due to their unique characteristic of
13 proximity to an interstate pipeline.

14 Q. Please explain how mains were allocated in each study.

15 A. Mains (excluding mains directly assigned to the MLS/MDS class) were separated
16 by that portion of mains that can only serve residential and SGS/SGDS customers
17 ("small customer mains") and that portion of mains that can be used to serve all
18 customers. The company's low pressure distribution system¹ can only serve
19 residential and small general service customers and thus the Company's low

¹ Under Federal code, a low pressure system is one that operates at customer equipment utilization pressure, i.e., 14 inches of water column or less (or a half pound of pressure or less).

1 pressure mains are allocated only to these customer classes. In addition to the
2 low pressure system, the Company's 2 inch mains were included in the amount to
3 be assigned to RS/RDS and SGS/SGDS since the large customers being served
4 under LGSS, SDS, and LDS (annual throughput over 64,400 therms) cannot be
5 served through a 2 inch main. The development of the small customer mains
6 amount to be assigned solely to RS/RDS and SGS/SGDS is included in Exhibit
7 JES-3, Development of Allocation Factors 5, 20 & 22, page 5. The same amount is
8 used in all three studies. In the customer demand study, this small customer
9 mains amount was allocated based on number of customers for RS/RDS and
10 SGS/SGDS.

11 Q. How was the remaining portion of mains allocated under the customer demand
12 study?

13 A. The remaining portion of mains under the customer demand study was allocated
14 to all classes (excluding MLS/MDS), recognizing a customer component utilizing
15 the minimum system concept, which is described in detail in Exhibit JES-3, pages
16 3 & 4 with the calculation shown in page 6. The minimum system concept
17 assumes that a base, or minimum system, is installed to connect customers, and
18 that the size of mains above that amount is established by customer demands. As
19 shown in the exhibit, the minimum system concept identified a significant
20 portion (approximately 52 percent) of these mains costs as being customer
21 related.

1 Q. Describe the methodology used in allocating mains in the peak and average study
2 (Exhibit No. 111, Schedule 2).

3 A. In the peak and average study (Exhibit No. 111, Schedule 2), design day demand
4 and annual demand are given equal weight regarding mains; therefore, the
5 demand component for each class was used to allocate 50% of the cost of mains
6 with average throughput quantities used to allocate the remaining 50%. The
7 weighted factor calculation for all rate schedules is presented in Exhibit JES-3,
8 page 5.

9 Q. How was the demand component for each class determined?

10 A. The demand component by class was provided by NiSource's Corporate Services
11 Company Commercial Operations department and represents expected
12 requirements under design day conditions. I note that the calculations reflect
13 design day total requirement, and thus assumes suppliers will make deliveries
14 necessary to meet customer requirements.

15 Q. Why was the MLS/MDS customer groups excluded from the above described
16 allocations of mains?

17 A. Customers served under rate schedules MLS/MDS were excluded from the
18 allocations of mains under all studies because these customers are served directly
19 from a Columbia Gas Transmission Corporation interstate pipeline or are in close
20 proximity to a Columbia Gas Transmission Corporation interstate pipeline.
21 Columbia has little or no main investment associated with providing service to

1 these customers. Identification of the mains investment in serving these customers
2 was made by studying the company's plant records and maps. The mains
3 investment cost then was directly assigned to MDS. Therefore, it is appropriate to
4 exclude them from the allocation of mains and mains related cost.

5 Q. Since a significant portion of the company's investment and expense is related to
6 mains and services does the allocation of those items dominate the outcome of the
7 studies?

8 A. Yes, it does. Mains and services account for approximately 87% of the company's
9 gross plant investment and approximately 17% of operating and maintenance
10 expenses, excluding gas costs. The allocation of these items significantly
11 influences the outcome of the studies. In addition, many other elements of
12 operation and maintenance expenses are allocated on plant-related factors.

13 Q. How are purchased gas costs allocated in the studies?

14 A. Gas costs are directly assigned to each class at the pro forma levels determined by
15 Company witness Bell (Columbia Statement No. 3) in her Exhibit No. 103,
16 Schedule No.1, Pages 11 and 20.

17 Q. Were there any other major operations and maintenance expense items that you
18 directly assign?

19 A. Yes. As shown on Page 8, Lines 10 and 16 of all three studies, I assigned recovery
20 of costs from the company's Universal Services Program ("USP") to the
21 residential class. Under both current and proposed rates, these costs are

1 recoverable from the residential class, whether sales or delivery service. Line 10
2 relates to the uncollectible component and Line 16 to the customer compliance
3 and other service costs provided to residential customers. This cost category
4 includes the costs associated with customer service activity for residential
5 customers including the costs associated with the Company's LIURP and
6 Emergency Service programs.

7 Q. How did you handle Uncollectibles related to Unbundling?

8 A. The total cost was match to the amount in revenue, and the portion related to small
9 customers was allocated based on DIS revenue and the large customer portion on
10 GMB/GTS revenue. A more detailed description of the allocation is included in
Exhibit JES-3.

12 Q Please describe how you allocated plant Account 380 - Services and the related
13 O&M accounts.

14 A. First, I identified the services related to MDS and directly assigned them. The
15 remaining investment in Account 380 - Services and the related O&M accounts was
16 based on an actual assignment of services installed on customers' premises.
17 Individual customer services were identified by size from the company's
18 Distributive Information System ("DIS") or billing system and accumulated by
19 customer class and rate schedule. Based on the historic test year per book data,
20 services were grouped between under three inches and three inches and over.
21 Average unit prices were developed from the data and applied to the number of

1 services under each rate schedule based on size. The resulting values, by rate
2 schedule, were converted to percentages and used to allocate service investment
3 and related expenses.

4 Q. Please explain the method of allocating Accounts 381 - Meters and 382 - Meter
5 Installations.

6 A. I have assigned meters to the various classes of customers based on an actual
7 inventory of meters installed on customers' premises. Columbia recognizes four
8 separate pressure groups for meters. Each varies in cost as the size increases.
9 Individual installed meters, as identified in DIS, were summarized by the four
10 pressure groups. The capitalized property investment, as identified on the
11 company's books and records for the four pressure groups, was divided by the
12 number of installed meters as reflected on the company's books and records to
13 develop a cost per meter for each group of meters. The costs per meter were
14 multiplied by the identified installed meters in DIS to determine the investment for
15 each customer class. The percentages were developed for Account 381 and used for
16 assigning Account 381 Meters as well as the investment in Account 382 Meter
17 Installations, 383 House Regulators and 384 House Regulator Installations, since
18 these costs are incurred in direct association with meters.

19 Q. Do you provide a more complete description of how these factors were developed
20 and the related calculations?

1 A. Yes. In Exhibits JES-2 and JES-3 of this testimony, entitled "Development of
2 Allocation Factors" and "Factors 5, 20 and 22", respectively, I have provided a
3 description and, where needed, a calculation for these and all other factors used
4 for the studies. In addition, in Exhibit JES - 4, I have provided the rationale for
5 factor selection, by account, as it pertains to the various categories of rate base
6 and expense.

7 Q. Did you prepare a study in support of the company's minimum or system charges?

8 A. I prepared two studies in support of the company's minimum or system charges.
9 They are contained in Exhibit No. 111, Schedule 1, pages 14 through 18.

10 Q. Please describe the two studies.

11 A. The study included in Schedule No. 1, pages 14 through 16 contains the company's
12 traditional system charge study based on the customer-demand ACOS study and
13 includes the customer portion of mains costs. Columbia has used this method in
14 support of its system charges in its previous general rate case filings. The study
15 shows a total company system charge of \$36.37 with the residential system charge
16 at \$33.46 and the SGS/SGDS at \$54.61(see Schedule 1, Page 14, Line 41, Columns
17 D, E, & F, respectively).

18 The study presented on pages 17 and 18 of Schedule No. 1 is similar, but excludes
19 the customer component of mains and other operations. The study shows a total
20 company system charge of \$19.31 with a residential system charge of \$18.00 and
21 the SGS/SGDS at 28.97 (see Page 17, Line 38, Columns D, E, & F, respectively).

1 Q. Why did you present this study?

2 A. To my understanding, other parties disagree with the inclusion of any mains costs
3 as a customer component and therefore I have included this calculation. The
4 Company does not agree with this approach, and continues to support its
5 traditional customer cost study.

6 Q. What is contained in Exhibit JES-5 and what is its purpose?

7 A. Company witness Strauss (Columbia Statement No. 15) asked for the revenue
8 change or impact on LDS to achieve the system average rate of return at proposed
9 rates. Exhibit JES-5 calculates the change in revenue needed to achieve the
10 system average of 8.52% at current/proposed rates. The revenue change was
11 calculated under all three studies. Witness Strauss used this information to
12 develop a cost based fourth block for rate schedule LDS.

13 Q. Does this complete your Prepared Direct Testimony?

14 A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
RESULTS SUMMARY - RATES OF RETURN BY RATE SCHEDULE

<u>Ln</u> <u>No.</u>	<u>Study</u> (1)	<u>System</u> <u>Return</u> (2)	<u>RS/RDS</u> (3)	<u>SGS/SGDS</u> (4)	<u>LGS</u> (5)	<u>SDS</u> (6)	<u>LDS</u> (7)	<u>MDS</u> (8)
<u>Customer/Demand</u>								
1	Current Rates	4.114%	2.358%	7.609%	8.367%	43.916%	34.618%	269.193%
2	Proposed Rates	8.520%	6.560%	13.901%	15.934%	47.024%	34.655%	269.472%
<u>Peak and Average</u>								
3	Current Rates	4.114%	3.934%	2.856%	3.450%	12.974%	5.277%	269.193%
4	Proposed Rates	8.520%	8.965%	6.885%	8.357%	14.140%	5.287%	269.472%
<u>Average Study</u>								
5	Current Rates	4.114%	3.075%	4.711%	5.382%	21.419%	11.526%	269.193%
6	Proposed Rates	8.520%	7.655%	9.624%	11.337%	23.115%	11.542%	269.472%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Direct Assignment

"Direct Assignment" refers to a specific identification and isolation of plant and/or expenses based on Columbia's accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term "direct" immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day

The quantities contained in Factor No. 1 represent the total demand projected to occur at Columbia's design peak day.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending June 30, 2014 are the basis for Factor No. 2.

Factor No. 3- Throughput Excluding MDS

Factor No. 3 represents the throughput quantities excluding MDS quantities for the twelve months ending June 30, 2014.

Factor No. 4- Gas Purchase Expense

Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending June 30, 2014 using the applicable Gas Cost Recovery ("GCR") rates.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 5 - Composite of Factors No. 1 and No. 3

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities included in Factor No. 3 to produce a composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. Please see Exhibit JES-3, Development of Allocation Factors Nos. 5, 20 & 22 for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending June 30, 2014 were averaged and used to develop Factor No. 6.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects revenue to be billed during the twelve months ending June 30, 2014 to small usage customers through the Company's Distributive Information System.

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending June 30, 2014 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of May 31, 2012.

Factor No. 10 - Forfeited Discounts

Factor No. 10 is based on the amount of forfeited discounts billed to customers during the twelve months ended May 31, 2012.

Factor No. 11 - Distribution Plant Excluding Other

Factor No. 11 ratios are based on the spread of distribution plant dollars, excluding gas plant accounts 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 11.

Factor No. 12 - Gross Plant

Factor No. 12 ratios are based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

Factor No. 14 reflects the relationship based on the spread of dollars in accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 14.

Factor No. 15 – Direct Assignment - Services

Factor No. 15 – reflects Services – Account 380 assigned by rate schedule based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size kind from the Company's Distributive Information System ("DIS") and accumulated by customer class and rate schedule. Based on the historic test year per book data, services were grouped between under three inches and three inches and over. Average unit prices were developed from the data and applied to the number of services under each rate schedule based on size. The resulting values, by rate schedule were converted to percentages and used to allocate service investment and related expenses.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

meters. Each varies in cost as the size increases. Individually installed meters as identified on Columbia's Distributive Information System ("DIS") were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters on DIS to determine the investment for each customer class. The percentages were developed for account 381 and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations, 383 House Regulators and 384 House Regulator Installations since these costs are incurred in direct relation with meters.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified on Columbia's plant records by rate schedule. The investment, so segregated, are aggregated and reduced to percentages to produce Factor No. 17.

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Line 20 Account 874 - Mains & Services

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

Factor No. 19 – O&M Excl Gas Pur, Uncollectibles, & A&G

Factor No. 19 is based on total Operating and Maintenance Expenses (Page 8, Line 37) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 7, 8, 9 & 10), USP Rider (Page 8, Line 16) and A&G Expenses (Page 8, Line 36).

Factor No. 20 Minimum System Mains

Factor No. 20 is used in the Customer-Demand Study. Please see Exhibit JES-3, Development of Allocation Factors Nos. 5, 20 & 22 for a description and development of Factor No. 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 21 – Large Customer Relations

Factor No. 21 is based on the accounts supported by the Large Customer Relations group.

Factor No. 22 – Average Factor Nos. 5 & 20

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study.

Factor No. 23 – Unbundled Uncollectibles

Factor No. 23 is based on the amounts to be billed to customers related to the unbundled un-collectibles accounts for the twelve months ending June 30, 2014.

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various FERC Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24.

Factor No. 25 – Sales and CHOICE Transportation

Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending June 30, 2014.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

Factor No. 5 – Composite Allocators 1 & 3

Factor No. 5 combines the design day quantities included in Factor No. 1 and the throughput quantities included in Factor No. 3 to allocated mains and mains related costs under for the Peak & Average study. Factor No. 5 reflects an equal weight of design day demand and annual demand under each rate class in creating Factor No. 5.

The first step in developing the factor was to identify the mains investment related to the company's low pressure system¹ and 2" pipe ("small customer mains"). This step is necessary since the company's larger customers under LGS, SDS and LDS cannot be served through these facilities.

To arrive at the low pressure mains amount, the company pulled from its Geographic Information System ("GIS"), a digital mapping system of the company's distribution system, the total footage of gas mains and low pressure pipe broken down between 2" main and non-2 inch main. These footages and related percentages are shown on Lns. 36 through 40 of Exhibit JES-3, page 5.

From the company's books and records as of the end of the historic test year, the value of all pipe is shown on Ln. 7. The percentage of non 2" low pressure pipe or 26.812% from Ln. 37 was applied to total pipe to arrive at a low pressure non- 2" pipe value or \$155,405,431, as shown on Ln. 9. The value of 2" pipe, again based on the

¹ Under Federal code, a low pressure system is one that operates at customer equipment utilization pressure, i.e., 14 inches of water column or less (or a half pound of pressure or less).

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

historic test year level, as shown on Ln. 13 was added to the non-2" low pressure pipe value to arrive at total 2" and non 2" low pressure pipe as shown on Ln. 14. The non-pipe value included in account 376 was split based on the ratio of 2" and non 2' pipe (\$252,889,989 – Ln. 14) to total pipe (\$579,611,484 – Ln. 7) or 43.631%.with the amount to be assigned to RS/SGS shown on Ln. 18. The non-pipe items include sleeves, couplings, clamps, pipe supports, valves, pipe fittings, pipe coating and welding costs, labor costs associated with stringing pipe and other items directly related to the pipe and charged to account 376 – mains. The pipe and non-pipe values, Ln. 14 and Ln. 18, were combined resulting in the \$397,497,367 of account 376 mains to be assigned to RS and SGS classes. Based on the fifty-fifty weighting of the RS to SGS design day demand, Ln. 20, and throughput, Ln. 22, 71.723%, Ln. 24, or \$285,097,037 of the \$397,497,367 is assigned to RS/RDS, and 28.277% or \$112,400,330 is assigned to SGS/SGDS (see Ln. 25).

The remaining mains amount shown on Ln. 26 or \$513,546,831 was allocated to the various rate schedules base on the 50%-50% weighting of the total company design day demand, Factor No. 1, and throughput quantities, Factor No. 3, as shown on Ln. 31. The results of the two allocations were added together, Ln. 25 and Ln. 32 and shown on Ln. 32. The individual rate schedule values were converted to percentages, Ln. 34, which formed Allocation Factor No. 5

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS
FACTOR NOS. 5, 20 & 22

Factor No. 20 – 2" Mains Minimum System

Factor No. 20 is a composite using customers and design day quantities to allocate mains. The development of the factor is presented on page 6 of Exhibit JES-3.

As with Factor No. 5, the total 2" and non 2" low pressure pipe and non-pipe totaling \$397,497,367, as shown on Ln. 19, was assigned to RS and SGS classes. The development of the \$397,497,367, as presented on page 5 is also presented on page 6, Lns. 1 through 19. For Factor No. 20, the allocation was based on the number of customers for these two classes. The amounts assigned to each class are shown on Ln. 22.

For the remaining pipe value, a minimum 2" system approach is used. Plant records were used as the basis for the minimum system study. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor. See

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FACTOR NOS. 5, 20 & 22

Lns. 34 through 42 for the development of the customer component of mains.

The next step in developing the minimum system ratios is to apply the customer component percentage 51.76% (Ln. 43) to Factor No. 6, average number of customers (see Ln. 25 & 26), and the demand component percentage 48.24% (Ln. 44) to Factor No. 1, Design Day, (see Lns. 28 & 29). Finally, then the two results (Ln. 26 & Ln. 29) are added together to form the minimum system percentages as shown on Ln. 30.

The Minimum System Allocation percentages as shown on Ln. 30 were applied to the remaining amount of mains. The results of the two allocations were added together, Ln. 22 and Ln. 31 and shown on Ln. 32. The individual rate schedule values were converted to percentages, Ln. 33, which formed Allocation Factor No. 20.

Factor No. 22 – Average of 5 & 20

Factor No. 22 is an average of Factor No. 5 and Factor No. 20 and is applied to mains and mains related costs to produce the Average study.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATION COST OF SERVICE

PEAK & AVERAGE

WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	RS/RDS (D) \$	SGS/SGDS (E) \$	LGS (F) \$	SDS (G) \$	LDS (H) \$	MDS (I) \$
1	Total Mains Plant in Service		911,143,079						
2	Less: Direct Mains Plant in Service		98,881	0	0	0	0	0	98,881
3	Allocable Mains Plant in Service		911,044,198						
4	Total All Pipe (376):		503,569,753						
5	Total All Pipe (376.30):		75,302,325						
6	Total All Pipe (376.80):		739,405						
7	Total All Pipe		579,611,484						
8	Percent Low Pressure greater than 2" gas Mains (pg. 2 ln. 3)		26.812%						
9	Low Pressure Non 2" Pipe		155,405,431						
10	Total 2" Pipe (376):		89,751,717						
11	Total 2" Pipe (376.30):		7,723,172						
12	Total 2" Pipe (376.80):		9,639						
13	Total 2" Pipe		97,484,528						
14	Total 2" Pipe and Non 2" Low Pressure Pipe (ln. 9 + ln. 13)		252,889,959						
15	Percentage of Total Acct 376 Pipe (ln. 14 / ln. 7)		43.631%						
16	Total Non-Pipe (ln. 3 - ln. 7)		331,432,715						
17	Percentage of Total Acct 376 Pipe (ln. 16)		43.631%						
18	Allocated Account 376 Non-Pipe (ln. 16 x ln. 17)		144,607,408						
19	Total 2" Pipe and Non 2" Low Pressure Pipe & non Pipe (ln. 14 + ln. 18)		397,497,367						
20	Design Day Volumes		65,770	47,600	18,170				
21	Percent Design Day		100.000%	72.373%	27.627%				
22	Throughput Volumes		46,129,238	32,785,788	13,343,450				
23	Percent Throughput		100.000%	71.074%	28.926%				
24	Composite Allocators ((line 21+ line 23) / 2)		100.000%	71.723%	28.277%				
25	Allocated 2" Pipe and Non 2" Low Pressure Pipe		397,497,367	285,097,037	112,400,330				
26	All Other Account 376 Plant in Service (ln. 3 - ln. 25)		513,546,831						
27	Design Day Volumes		781,900	476,000	181,700	9,300	41,700	73,200	
28	Percent Design Day		100.000%	60.878%	23.238%	1.189%	5.333%	9.362%	
29	Throughput Volumes		71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	
30	Percent Throughput		100.000%	45.616%	18.566%	1.296%	9.772%	24.750%	
31	Composite Allocators ((line 28 + line 30) / 2)		100.000%	53.246%	20.902%	1.243%	7.553%	17.056%	
32	Alloc All Other Acct 376 Plant in Service		513,546,831	273,443,145	107,341,559	6,383,387	38,788,192	87,590,548	
33	Total Alloc Account 376 Mains (ln 24 + ln 32)		911,044,198	558,540,182	219,741,889	6,383,387	38,788,192	87,590,548	
34	ALLOCATOR #5		100.000%	61.307%	24.120%	0.701%	4.258%	9.614%	
35	As of September 15, 2012								
36	Low Pressure 2" gas Mains	2,480,671	5.807%						
37	Low Pressure greater than 2" gas Mains	11,453,212	26.812%						
38	Total Low Pressure gas Mains	13,933,883	32.619%						
39	Non Low Pressure	28,782,799	67.381%						
40	Total CPA gas Mains	42,716,682	100.000%						

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC (B)	TOTAL COMPANY (C) \$	RS/RDS (D) \$	SGS/SGDS (E) \$	LGS (F) \$	SDS (G) \$	LDS (H) \$	MDS (I) \$
1	Total Mains Plant in Service		911,143,079						
2	Less: Direct Mains Plant in Service		<u>98,881</u>	0	0	0	0	0	98,881
3	Allocable Mains Plant in Service		911,044,198						
4	Total All Pipe (376):		503,569,753						
5	Total All Pipe (376.30):		75,302,325						
6	Total All Pipe (376.80):		<u>739,405</u>						
7	Total All Pipe		579,611,484						
8	Percent Low Pressure greater than 2" gas Mains (pg. 2 ln. 1)		<u>26.812%</u>						
9	Low Pressure Non 2" Pipe		155,405,431						
10	Total 2" Pipe (376):		89,751,717						
11	Total 2" Pipe (376.30):		7,723,172						
12	Total 2" Pipe (376.80):		<u>9,639</u>						
13	Total 2" Pipe		97,484,528						
14	Total 2" Pipe and Non 2" Low Pressure Pipe (ln. 9 + ln. 13)		252,889,959						
15	Percentage of Total Acct 376 Pipe (ln. 14 / ln. 7)		43.631%						
16	Total Non-Pipe (ln. 3 - ln. 7)		331,432,715						
17	Percentage of Total Acct 376 Pipe (ln. 16)		<u>43.631%</u>						
18	Allocated Account 376 Non-Pipe (ln. 16 x ln. 17)		144,607,408						
19	Total 2" Pipe and Non 2" Low Pressure Pipe & non Pipe (ln. 14 + ln. 18)		397,497,367						
20	Number of Customers		414,751	378,379	36,372				
21	Percent Customers		100.000%	91.230%	8.770%				
22	Allocated 2" Pipe and Non 2" Low Pressure Pipe		397,497,367	362,636,848	34,860,519				
23	All Other Account 376 Plant in Service (ln. 3 - ln. 22)		513,546,831						
24	Number of Customers		415,337	378,379	36,372	79	416	91	
25	Percent Customers		100.000%	91.102%	8.757%	0.019%	0.100%	0.022%	
26	Customer Component	51.76%		47.154%	4.533%	0.010%	0.052%	0.011%	
27	Design Day Volumes		781,900	476,000	181,700	9,300	41,700	73,200	
28	Percent Design Day Volumes		100.000%	60.878%	23.238%	1.189%	5.333%	9.362%	
29	Demand Component	48.24%		29.368%	11.210%	0.574%	2.573%	4.516%	
30	Minimum System Allocation Factor (ln. 26 + ln. 29)			76.522%	15.743%	0.584%	2.625%	4.527%	
31	Alloc All Other Acct 376 Plant in Service		513,546,831	392,971,171	80,847,678	2,999,113	13,480,604	23,248,265	
32	Total Alloc Account 376 Mains (ln. 21 + ln. 30)		911,044,198	755,608,019	115,708,197	2,999,113	13,480,604	23,248,265	
33	Composite Mains Allocation Factor		100.000%	82.938%	12.701%	0.329%	1.480%	2.552%	
2" MINIMUM SYSTEM CALCULATION									
			<u>Footage</u>	<u>Amount</u>	<u>Unit Cost</u>				
34	Total 2" Pipe (376):		8,922,771	89,751,717					
35	Total 2" Pipe (376.30):		3,840,376	7,723,172					
36	Total 2" Pipe (376.80):		<u>16,383</u>	<u>9,639</u>					
37	Total 2" Pipe		12,779,530	97,484,528	\$7.63				
38	Total All Pipe (376):		21,307,190	503,569,753					
39	Total All Pipe (376.30):		17,715,858	75,302,325					
40	Total All Pipe (376.80):		<u>295,811</u>	<u>739,405</u>					
41	Total All Pipe [2]		39,318,859	579,611,484					
42	Unit Cost x Total All Pipe:			300,002,894					
43	Customer Component (Line 15 / Line 14):			0.5176					
44	Demand Component (Line 18 - Line 16):			<u>0.4824</u>					
45	TOTAL			1.0000					
46	As of September 15, 2012								
47	Low Pressure 2" gas Mains		2,480,671	5.807%					
48	Low Pressure greater than 2" gas Mains		<u>11,453,212</u>	<u>26.812%</u>					
49	Total Low Pressure gas Mains		13,933,883	32.619%					
50	Non Low Pressure		<u>28,782,799</u>	<u>67.381%</u>					
51	Total CPA gas Mains		42,716,682	100.000%					

[1] Customer Count excludes final bills.

[2] Does not tie directly to 376/376.30/376.80, due to inclusion of pipe only (not valves, labor, etc.).

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

**GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 –
PAGE 3**

INTANGIBLE PLANT - PAGE 3 (101-106-107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

UNDERGROUND STORAGE PLANT - PAGE 3 (101-106-107)

Accounts 350 through 355

Underground Storage Plant was allocated using Factor No. 25 – Sales and CHOICE Transportation activity for the twelve months ending June 30, 2014 reflecting its peaking support for sales and CHOICE customers.

DISTRIBUTION PLANT - PAGE 3 (101-106-107)

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 17 since these structures house measuring and regulating stations serving the larger customer groups only.

Account 376 – Mains

Non-directly assigned mains were allocated by rate schedule based on the weighting of design day and annual throughput, Factor No. 5, for the peak and average study. For the Customer-Demand study such investment was based on Factor No. 20 which provides a customer component based on a 2" "Minimum System" with the remaining portion assigned on design-day. For the Average study, Factor No. 5 and Factor No. 20 are averaged to assign the

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Mains costs to the various rate schedules. Please see Exhibit JES-2 for a detailed description of Factor Nos. 5 & 20.

Direct Mains

Mains for Main Line Delivery Service ("MDS") were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Mains - Related Accts

Accounts related to/or supports the mains gas plant account were allocation on Factor No. 5 under the Peak and Average study, Factor No. 20 under the Customer-Demand study, and Factor No. 22 under the Average study since these accounts directly support the mains investment. The mains-related accounts generally include the follow gas plant accounts: 374.10, 374.20, 374.30, 374.40, 374.41, 374.50, 375.20, 375.31, 375.40, 375.70, 378.10, 378.20, 378.30, 379.10 and 379.11.

Direct Mains - Related Accts

Similarly to the mains - related accounts above, these are accounts that support the mains that were directly assigned to MDS and include accounts 374.40, 374.50, and 378.20. Like direct – mains, the amounts were identified from the company's maps and accounting records and directly assigned.

Account 380 - Services

Account 380 - Services was assigned by rate schedule based on a direct assignment of the investment costs. A more detailed description of the study is contained in Exhibit JES-2 the Development of Allocation Factors.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 380 – Direct Services

Like mains, services for MDS were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Accounts 381, 382, 383 and 384

Meters and Meter Installations, House Regulators and House Regulator Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in Exhibit JES-2, the Development of Allocation Factors and Statement No. 9. This methodology represents virtually a direct assignment of costs to the various customer groups. Accounts 382, 383, and 384 were allocated using Factor No. 16 since these costs are incurred in direct relation with the meters.

Account 385

Industrial Measuring and Regulating Stations were allocated using Factor No. 17 which was based on a review of Columbia's records as explained in Exhibit JES-2, the Development of Allocation Factors. Measuring stations were segregated by rate schedule. This methodology represents virtually a direct assignment of costs to the various customer groups.

Dist Plant Excl Other Allocated

This investment consists of gas plant accounts 375.70, 375.71 and all 387 and was allocated to the various rate schedules using Factor No. 11. Factor No. 11 was based on distribution plant specifically assigned and was used to assign general investment and costs that support the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

General Plant

General plant includes items such as general tools (cars, trucks, backhoes, etc), communication equipment, office furniture and fixtures, and other miscellaneous equipment. Like general distribution plant, this plant investment supports the delivery of natural gas and therefore Factor No. 11 was used to assign the investment.

RESERVE FOR DEPRECIATION - PAGE 4

Depreciation Reserve was calculated on an account by account basis using the same allocation factors that were used to allocate all gross plant accounts

DEPRECIATION & AMORTIZATION EXPENSE and NET NEGATIVE SALVAGE - PAGE 5

Depreciation and amortization expense was allocated by gas plant account on the same allocations as the Gross Original Cost. Amortization of net negative salvage was allocated using Factor 11 based on its remediation of distribution type facilities.

OPERATING REVENUE AT CURRENT AND PROPOSED RATES - PAGE 6

Sales and Transportation Revenue

Sales and transportation revenue was directly assigned as presented in Exhibit No. 103 for the fully forecasted rate year and supported by Witness Melissa Bell.

Accounts 487

Forfeited discounts were allocated using Factor No. 10 which was developed from actual forfeited discounts billed by rate class during the historic test year twelve months ended May 31, 2012.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 488, 493 and 495

Rents, Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served.

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully forecasted rate year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4 which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, since these costs benefit customers in the way that all other distribution costs provide benefit.

Account 871

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains since these are costs incurred monitoring and directing the flow of gas through the distribution system.

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 – Direct Assignment – IND M&R - since these costs are incurred in direct association with the stations in Account 385.

Accounts 878 and 879

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in Exhibit JES-2, the Development of Allocation Factors, and Statement No. 9. This methodology represents virtually a direct assignment of costs to the various customer classes. Expenses for House Regulators and Customer Installations were allocated using Factor No. 16 since these costs are incurred in direct relation with the meters.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

DISTRIBUTION EXPENSES – MAINTENANCE - PAGE 7

Accounts 885 and 894

General costs for supervision and engineering and maintenance costs of other equipment of the distribution function were allocated using Factor No. 18 other distribution expense since these costs benefit customers in the same way that all other distribution costs provide benefit.

Account 887

Mains Maintenance Expense was allocated using Factor No. 13, which reflects the spread of Account 376 Mains among all customer classes, since plant and expense functions are directly related.

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 - Direct Assignment – IND M&R - since these costs are incurred in direct relation with the stations in Account 385.

Account 892

Expenses for Services were allocated using Factor No. 15 which was based on size of service and size of customer as explain above under Gas Plant Account 380 – Services and in Statement No. 9.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 893

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in Exhibit JES-2, the Development of Allocation Factors, and Statement No. 9. This methodology represents virtually a direct assignment of costs to the various customer classes. Expenses for House Regulators and Customer Installations were allocated using Factor No. 16 since these costs are incurred in direct relation with the meters.

CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES EXPENSES - PAGE 8

Account 904 – Uncollectibles – DIS Revenue & Uncollectibles GMB/GTS Revenue

These cost categories represent traditional bad debts. They have been separated between the two classes of customers and allocated based on the revenue related to each as included in Factor No. 7 for DIS and Factor No. 8 for GMB/GTS, respectively.

Account 904 Uncollectibles – Unbundled

These costs were directly assigned to each rate schedule consistent with the levels included in revenue for the fully forecasted rate year as presented in Exhibit No. 103. Factor No. 23 reflects this assignment.

Account 904 – Direct USP Uncollectibles

These uncollectibles are directly related to the Company's Customer Assistance Program ("CAP") available to residential customers and are recoverable from the residential class whether sales or delivery service. The amounts shown are reflected in revenue for the fully forecasted rate year as presented in Exhibit No. 103.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Customer Accounts

Customer Accounts includes meter reading, customer records, and credit and collection activities recorded in accounts 901 through 903, 905, and 921. These costs were allocated using Factor No. 6, Average Number of Customers, since they are directly related to the number of customers served.

Customer Service Information

Customer Service and Informational Costs are reflected in accounts 907 through 910 plus related costs in 921 and 931. These costs were allocated using Factor No. 6 since all customers may benefit except account 908 – Direct USP/LIURP/HEEP. These costs include the recovery of specific customer programs benefiting residential customers. The amounts reflect the recovery included in revenue as presented in Exhibit No. 103 for the fully forecasted rate year. Account 910, Large Customer Relations, was allocated using Factor No. 21 which is based on the number of accounts managed by this group.

Sales Expense

Sales expenses, accounts 912 and 913, were allocated using Factor No. 6, Average Number of Customers, since these activities directly support customers served.

ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8

Admin. & General Expenses (Line 36)

General Office Expenses, and to a lesser degree, District and Local Office Expenses in this function classification, plus company-wide expenses excluding Employee Benefits, account 926, such as Injuries and Damages, Insurance, and Regulatory Commission Expense were all

**COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE**

allocated using Factor No. 19 - Total Operation & Maintenance Excluding Gas Purchased, A & G, Uncollectibles and USP rider costs. These costs are regarded as overhead to the entire company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. Employee Pensions & Benefits, account 926, was allocated on Factor No. 24, Labor, since they are directly related to company labor.

TAXES OTHER THAN INCOME - PAGE 9

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 11 - Distribution Plant excluding Other due to a direct relationship with Plant in Service. Similarly, PA Capital Stock and License and Franchise Taxes were allocated using Factor No. 11 as they are also related to Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly, have been allocated based on Factor No. 24 – Labor. State Sales and Use Tax and Other Taxes were allocated using Factor 19 since these taxes are generally related to the purchase of supplies.

RATE BASE SUMMARY - PAGE 10

Account 154

Materials and Supplies were allocated based on Factor 11, Distribution Plant Excluding Other, reflecting the primary future use of such inventory.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 164 & 117

Gas Stored Underground, both current and long term, was allocated based on Factor No. 25, Sales and CHOICE Transportation, reflecting the support of these customers in meeting their design day and seasonal requirements.

Account 165

Prepayments consist primarily of commission fees and corporate insurance therefore they were allocated using Factor 19, Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs.

Accounts 190, 282 and 283

All deferred income taxes included in rate base are plant related therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor 9, Direct Assignment – Customer Deposits.

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 11 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustment over book are plant related, i.e., tax depreciation over book depreciation and, therefore, the tax deductions were allocated using Factor No. 12, Gross Plant.

In calculating the Federal and State income taxes for each rate schedule, the effective Federal and State income tax rates were used. Income taxes were calculated for each customer class.

COLUMBIA GAS OF PENNSYLVANIA, INC.
REVENUE CHANGE AT SYSTEM AVERAGE FOR LDS

Ln No.	DESCRIPTION	ACOS STUDIES		
		CUSTOMER DEMAND SCHEDULE 1 (1)	PEAK & AVERAGE SCHEDULE 2 (2)	AVERAGE STUDY SCHEDULE 3 (3)
1	OPERATING INCOME @ PROPOSED REVENUE	5,873,560	3,310,529	4,591,908
2	RATE BASE [PAGE 10]	16,948,685	62,616,057	39,783,380
3	RATE OF RETURN EARNED ON RATE BASE	34.655%	5.287%	11.542%
4	REQUESTED RATE OF RETURN ("ROR")	8.520%	8.520%	8.520%
5	OPERATING INCOME AT REQUESTED ROR (LN. 4 X LN. 2)	1,444,028	5,334,888	3,389,544
6	OPERATING INCOME SURPLUS/(DEFICIENCY) (LN. 1 - LN. 5)	4,429,532	(2,024,359)	1,202,364
7	GROSSUP FACTOR (EXHIBIT NO. 102, SCHEDULE 2)	<u>1.73450116</u>	<u>1.73450116</u>	<u>1.73450116</u>
8	SURPLUS (DEFICIENCY) REVENUE (LN. 6 X LN. 7)	<u>7,683,029</u>	<u>(3,511,253)</u>	<u>2,085,502</u>

2-13-13

Hbg R

COLUMBIA GAS OF PENNSYLVANIA, INC.

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2012-2321748

Columbia Gas of Pennsylvania, Inc.
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
Bcfy	Billion cubic feet per year
$b \times r$	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CEG	Columbia Energy Group
CPA	Columbia Gas of Pennsylvania, Inc.
CPFF	Commercial Paper Funding Facility
DCF	Discounted Cash Flow
FFO	Funds from Operations
FOMC	Federal Open Market Committee
FFRY	Fully Forecasted Rate Year
g	Growth rate
GSE	Government-sponsored enterprises
IGF	Internally Generated Funds
LDC	Local Distribution Companies
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
MLPs	Master Limited Partnerships
P-E	Price-earnings
PPUC	Pennsylvania Public Utility Commission
PUHCA	Public Utility Holding Company Act of 2005
PUC	Public Utility Commission

[illegible][illegible]

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PPUC" or the "Commission") should recognize in the determination of the revenues that Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit No. 400, which is a multi-page document divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A. Based upon my analysis of the Company and the superior performance of its management, as described in the testimony of Mr. Mark R. Kempic, President of the Company (Columbia Statement No. 1), it is my opinion that the rate of return on common equity should be set at 11.25%. As shown on Schedule 1, I have presented the weighted average cost of capital for the Company, which is calculated with the June 30, 2014 Fully Forecasted Rate Year ("FFRY"). The resulting overall cost of

capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is wholly-owned subsidiary of Columbia Energy Group ("CEG"), which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource was created as part of the acquisition of CEG by NIPSCO Industries, Inc., the former name of NiSource Inc. NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, and other energy investments.

The Company provides natural gas distribution service to approximately 415,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended May 31, 2012 was represented by approximately 40% to sales customers and approximately 60% to transportation customers. CPA obtains its gas supplies from producers and marketers and has transportation arrangements through connections with six interstate pipelines. The Company has storage arrangements with three suppliers to supplement flowing gas.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"),

1 the Comparable Earnings ("CE") approach.

2 **Q. In your opinion, what factors should the Commission consider when**
3 **determining the Company's cost of capital in this proceeding?**

4 A. The Commission should consider the ratesetting principles that I have set forth in
5 Appendix B. In this regard, the Commission's rate of return allowance must be set to
6 cover the Company's interest and dividend payments, provide a reasonable level of
7 earnings retention, produce an adequate level of internally generated funds to meet
8 capital requirements, be commensurate with the risk to which the Company's capital is
9 exposed, support reasonable credit quality, and allow the Company to raise capital on
10 reasonable terms.

11 **Q. How have you measured the cost of equity in this case?**

12 A. The models that I used to measure the cost of common equity for the Company were
13 applied with market and financial data developed from a group of nine (9) gas
14 companies. The companies are identified on page 2 of Schedule 3. I will refer to
15 these companies as the "Gas Group" throughout my testimony.

16 **Q. Please explain the selection process used to assemble the Gas Group?**

17 A. I began with the all of gas utilities contained in The Value Line Investment Survey,
18 which consists of eleven companies. Value Line is an investment advisory service that
19 is a widely used source in public utility rate cases. Through the application of my
20 screening process, I eliminated two companies, which were NiSource and UGI
21 Corporation. The eliminations were attributed to operational differences and
22 diversification, as identified in page 2 of Schedule 3. The remaining nine companies
23 are included in my Gas Group.

24 **Q. How have you performed your cost of equity analysis with the market data for**
25 **the Gas Group?**

26 A. I have applied the models/methods for estimating the cost of equity using the average

1 data for the Gas Group. I have not measured separately the cost of equity for the
2 individual companies within the Gas Group, because the determination of the cost of
3 equity for an individual company can be problematic. The use of group average data
4 will reduce the effect of potentially anomalous results for an individual company if a
5 company-by-company approach were utilized. This is to say, by employing group
6 average data, rather than individual company analysis; I have helped to minimize the
7 effect of extraneous influences on the market data for an individual company.

8 **Q. Please summarize your cost of equity analysis.**

9 A. My cost of equity determination was derived from the results of the methods/models
10 identified above. In general, the use of more than one method provides a superior
11 foundation to arrive at the cost of equity. At any point in time, any single method can
12 provide an incomplete measure of the cost of equity. The specific application of these
13 methods/models will be described later in my testimony. The following table provides
14 a summary of the indicated costs of equity using each of these approaches.

DCF	10.55%
RP	11.01%
CAPM	11.13%
CE	12.70%

15 As I will discuss later, CPA has more risk than the Gas Group attributed to its weaker
16 credit quality, its smaller size, its more variable returns, and other factors. To the
17 extent that these higher risk factors can be quantified, they are reflected in the results
18 shown above. The average of all methods is 11.35% and the median of all methods is
19 11.07%. From these measures, I recommend a cost of equity in the range of 11.0% to
20 11.3%. Mr. Kempic has shown that the Company ranks high in customer service and
21 management efficiency. In recognition of its outstanding performance, the Company
22 should be granted an opportunity to earn an 11.25% rate of return on common equity,
23 which is ten (10) basis points above the midpoint of my range of 11.0% to 11.3%. To

1 obtain new capital and retain existing capital, the rate of return on common equity must
2 be high enough to satisfy investors' requirements. Indeed, in a study dated December
3 9, 2008, prepared for the American Gas Foundation, it was noted that allowed equity
4 returns below the level required by investors may lessen a utility's ability to maintain
5 and develop systems that are necessary to provide natural gas service efficiently.
6 Furthermore, the report specifically found that returns below 10% would trigger broad
7 disenchantment with LDC investment.

8 **NATURAL GAS RISK FACTORS**

9 **Q. What factors currently affect the business risk of natural gas utilities?**

10 A. Gas utilities face risks arising from competition, economic regulation, the business
11 cycle, and customer usage patterns. Today, they operate in a more complex
12 environment with time frames for decision-making considerably shortened. Their
13 business profile is influenced by market-oriented pricing for the commodity distributed
14 to customers and open access for the transportation of natural gas for customers.

15 Natural gas utilities have focused increased attention on safety and reliability
16 issues and on conservation. In order to address these issues and to comply with new
17 and pending pipeline safety regulations, natural gas companies are now allocating
18 more of their resources to addressing aging infrastructure issues. The testimony of
19 Mr. Kempic and other Company witnesses discuss the investments that the Company
20 will make to address these issues.

21 The Company also faces a series of risks that impact its cost of equity. In the
22 western area of Pennsylvania, the Company operates in a unique situation with
23 overlapping service territories, which enable other gas utilities to compete with one
24 another for customers. Further, there are six interstate pipelines that traverse the
25 Company's service territory. This situation exposes the Company to bypass for certain
26 large volume customers. Finally, the existence of local gas production provides a

bypass threat to the Company. This situation will only become more intense with the production from the Marcellus Shale formation. Overall, the Company's risk of competition is considerably higher than that faced by many LDCs, including the members of the Gas Group that I used to measure the Company's cost of equity.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. For these sales, the Company's revenues are subject to variations caused by weather abnormalities. In addition, the Company has determined that its weather-adjusted residential sales have declined significantly over the past several years as discussed in the testimony of Witness Amy Efland (Columbia Statement No. 2). While the improved rate design proposed in this case can mitigate the impact of declining average use for residential customers, the loss of load due to conservation and fuel switching cannot be mitigated for large volume customers. It is noteworthy that the Company currently does not have a revenue decoupling mechanism that has become increasingly common for natural gas utilities. Revenue decoupling is a mechanism that seeks to separate the recovery of fixed costs from the volume of gas delivered to customers.

Q. Does your cost of equity analysis and recommendation take into account the rate design that the Company is proposing in this case?

A. Yes. The Company proposes to implement a tariff provision that is designed to decouple forecast revenues from variations in sales related to usage due to weather, energy efficiency efforts, and other factors. All but one of the companies in my Gas

1 Group has some form of revenue stabilization mechanism that encompasses the
2 Company's proposal. The sole exception is Laclede, which has a weather mitigated
3 rate design that recovers its fixed costs more evenly during the heating season.
4 Therefore, the market prices of these companies' common equity reflect the
5 expectations of investors that the companies' revenues are stabilized to some extent
6 by a decoupling mechanism. Therefore my analysis reflects the impacts of decoupling
7 on investor expectations through the use of market-determined models. If the
8 Company is unable to obtain the rate design that it proposes in this case, its risk will
9 remain above that of the Gas Group that serves as a basis to measure the Company's
10 cost of equity, i.e., the Gas Group's cost of equity will understate the return that is
11 appropriate for the Company.

12 **Q. The Pennsylvania legislature has recently passed a statute that will enable the**
13 **creation of a DSIC for natural gas and electric utilities. How will the DSIC affect**
14 **the Company's cost of capital?**

15 A. The cost of capital for CPA will not be affected by the implementation of the DSIC. I
16 say this because many of the proxy group companies whose data has been used to
17 develop the cost of equity for CPA in this proceeding have a DSIC or similar
18 infrastructure rehabilitation mechanisms. Indeed, AGL Resources, Atmos Energy,
19 Laclede Group, New Jersey Resources and South Jersey Industries make use of the
20 DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit
21 of the DSIC, or other regulatory mechanisms, that impact is already reflected in the
22 market evidence of the cost of equity for the proxy group. Moreover, I am unaware of
23 any of those states where these companies operate which have reduced the equity
24 return for the gas utilities upon implementation of the DSIC. Indeed, the Commission
25 has never adjusted the cost of equity for water utilities, which have employed a DSIC
26 for over a decade. Implementation of the DSIC will represent a positive step that will

1 align the Company with many of the companies that make up my proxy group. It
2 should be noted however, that with the availability of the FFRY, the DSIC cannot be
3 implemented for an extended period of time.

4 **Q. How does the Company's throughput to large volume users affects its risk**
5 **profile?**

6 A. The Company's risk profile is influenced by natural gas delivered to its large industrial
7 and commercial customers, as demonstrated by the fact that gas throughput to the
8 Company's 157 major account customers represents approximately 36.3% of the
9 Company's total throughput. In addition, the ten largest customers by volume
10 represent 9.5 million Dth of throughput during the twelve months ended May 31, 2012.
11 Generally speaking, there are four primary threats to throughput to the Company's
12 largest volume users. First, the Company experiences attrition in this large customer
13 group, having lost 5 large industrial or commercial customers since the last case.
14 Second, the Company's largest customers, which have traditionally used
15 transportation service, have the ability to bypass the Company's system to other gas
16 supply sources such as interstate pipelines, other local distribution companies, or
17 nonregulated pipeline contractors. In this regard, the Company has identified 18.7
18 million Dth per year of large customer throughput that is susceptible to such bypass.
19 Third, in addition to the bypass threat, a material portion of the large customer
20 throughput is also exposed to fuel switching to coal, oil, propane, bio fuels, or other
21 energy sources depending on the fluctuating costs of these different fuels in
22 comparison with natural gas. Finally, in its effort to retain load, the Company is
23 vulnerable to the impacts of business cycles, competition within its customers'
24 industries, and other external factors that can result in shifts of production to customer
25 facilities that are not served by the Company. All of these risks put fixed cost recovery
26 for this class of customers at risk.

1 **Q. Please indicate how the Company's construction program affects its risk profile.**

2 A. The Company is faced with the requirement to undertake investments to maintain and
3 upgrade existing facilities in its service territory. To maintain safe and reliable service
4 to existing customers, the Company must invest to upgrade its infrastructure. The
5 rehabilitation of the Company's infrastructure represents a non-revenue producing use
6 of capital. Although the Company has made significant strides in reducing its
7 percentage of cast iron and unprotected steel pipe, they still represent 1,878 miles (or
8 approximately 25%) of its distribution mains as of year-end 2011. The Company also
9 has 65,557 (or approximately 16%) of its services constructed of unprotected steel.
10 For the future, the Company expects its net capital expenditures, to be:

Year	Capital Expenditures
2012	\$ 145,334,000
2013	\$ 167,444,000
2014	\$ 169,565,000
2015	\$ 135,608,000
2016	\$ 137,190,000
Total	\$ 755,141,000

11 The Company's total capital expenditures over the next five years will represent
12 approximately 90% ($\$755,141,000 \div \$841,498,351$) of the net utility plant in service at
13 December 31, 2011.

14 **Q. How should the Commission respond to the issues facing the natural gas**
15 **utilities and in particular CPA?**

16 A. The Commission should recognize and take into account the competitive environment
17 in the natural gas business in determining the cost of capital for the Company, and
18 provide a reasonable opportunity for the Company to actually achieve its cost of
19 capital. A fair rate of return also represents a key to a financial profile that will provide

1 the Company with the ability to raise the capital necessary to meet its capital needs on
2 reasonable terms.

3 **FUNDAMENTAL RISK ANALYSIS**

4 **Q. Is it necessary to conduct a fundamental risk analysis to provide a framework**
5 **for a determination of a utility's cost of equity?**

6 A. Yes, it is. It is necessary to establish a company's relative risk position within its
7 industry through a fundamental analysis of various quantitative and qualitative factors
8 that bear upon investors' assessment of overall risk. The qualitative factors that bear
9 upon Company risk have already been discussed previously. The quantitative risk
10 analysis follows. The items that influence investors' evaluation of risk and its required
11 returns are described in Appendix C. For this purpose, I compared the Company to
12 the S&P Public Utilities, an industry-wide proxy consisting of various regulated
13 businesses, and to the Gas Group.

14 **Q. What are the components of the S&P Public Utilities?**

15 A. The S&P Public Utilities is a widely recognized index that is comprised of electric
16 power and natural gas companies. These companies are identified on page 3 of
17 Schedule 4.

18 **Q. What companies comprise the gas group?**

19 A. My Gas Group consists of the following companies: AGL Resources, Inc., Atmos
20 Energy Corp., Laclede Group, Inc., New Jersey Resources Corp., Northwest Natural
21 Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Inc., Southwest Gas
22 Corporation, and WGL Holdings, Inc.

23 **Q. Is knowledge of a utility's bond rating an important factor in assessing its risk**
24 **and cost of capital?**

25

1 A. Yes. Knowledge of a company's credit quality rating is important because the cost of
2 each type of capital is directly related to the associated risk of the firm. So while a
3 company's credit quality risk is shown directly by the rating and yield on its bonds,
4 these relative risk assessments also bear upon the cost of equity. This is because a
5 firm's cost of equity is represented by its borrowing cost plus compensation to
6 recognize the higher risk of an equity investment compared to debt.

7 **Q. How do the credit quality ratings compare for the Company, the Gas Group, and**
8 **the S&P Public Utilities?**

9 A. Presently, the NiSource credit quality ratings are Baa3 from Moody's Investors Service
10 ("Moody's") and BBB- from Standard & Poor's Corporation ("S&P"). These ratings for
11 NiSource represent the Long Term ("LT") issuer rating by Moody's and the corporate
12 credit rating ("CCR") designation by S&P, which focuses upon the credit quality of the
13 issuer of the debt rather than upon the debt obligation itself. S&P has assigned an
14 "excellent" business risk profile and an "aggressive" financial risk profile to NiSource.
15 The ratings for NiSource are at the bottom of the investment grades.

16 For the Gas Group, the average LT issuer rating is A3 by Moody's and the
17 average CCR is A by S&P, as displayed on page 2 of Schedule 3. For the S&P Public
18 Utilities, the average credit quality rating is Baa1 by Moody's and BBB+ by S&P, as
19 displayed on page 3 of Schedule 4. Many of the financial indicators that I will
20 subsequently discuss are considered during the rating process.

21 **Q. How do the financial data compare for the Company, the Gas Group, and the**
22 **S&P Public Utilities?**

23 A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3,
24 and 4. The data cover the five-year period 2007-2011. The important categories of
25 relative risk may be summarized as follows:

26 Size. In terms of capitalization, the Company is smaller than the average size

1 of the Gas Group, and smaller still than the average size of the S&P Public Utilities.
2 All other things being equal, a smaller company is riskier than a larger company
3 because a given change in revenue and expense has a proportionately greater impact
4 on a small firm. As I will demonstrate later, the size of a firm can impact its cost of
5 equity.

6 Market Ratios. Market-based financial ratios, such as earnings/price ratios and
7 dividend yields, provide a partial measure of the investor-required cost of equity. If all
8 other factors are equal, investors will require a higher rate of return for companies that
9 exhibit greater risk, in order to compensate for that risk. That is to say, a firm that
10 investors perceive to have higher risks will experience a lower price per share in
11 relation to expected earnings.¹

12 There are no market ratios available for the Company because its stock is
13 owned by CEG, which in turn is owned by NiSource. The five-year average price-
14 earnings multiple was somewhat higher for the Gas Group as compared to the S&P
15 Public Utilities. The five-year average dividend yield was lower for the Gas Group as
16 compared to the S&P Public Utilities. The five-year average market-to-book ratio was
17 somewhat higher for the Gas Group as compared to the S&P Public Utilities.

18 Common Equity Ratio. The level of financial risk is measured by the proportion
19 of long-term debt and other senior capital that is contained in a company's
20 capitalization. Financial risk is also analyzed by comparing common equity ratios (the
21 complement of the ratio of debt and other senior capital). That is to say, a firm with a
22 high common equity ratio has lower financial risk, while a firm with a low common
23 equity ratio has higher financial risk. The five-year average common equity ratios,

¹For example, two otherwise similarly situated firms each reporting \$1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

1 based on permanent capital were 54.3% for CPA, 54.8% for the Gas Group, and
2 44.8% for the S&P Public Utilities. The common equity ratios were similar for CPA and
3 the Gas Group, thereby indicating similar financial risk.

4 Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned
5 returns signifies relatively greater levels of risk, as shown by the coefficient of variation
6 (standard deviation ÷ mean) of the rate of return on book common equity. The higher
7 the coefficients of variation, the greater degree of variability. For the five-year period,
8 the coefficients of variation were 0.196 (2.2% ÷ 11.2%) for the Company, 0.063 (0.7%
9 ÷ 11.1%) for the Gas Group, and 0.107 (1.2% ÷ 11.2%) for the S&P Public Utilities.
10 The variability of the Company's rates of return was higher than the Gas Group and
11 the S&P Public Utilities, thereby signifying higher risk for the Company.

12 Operating Ratios. I have also compared operating ratios (the percentage of
13 revenues consumed by operating expense, depreciation, and taxes other than
14 income).² The five-year average operating ratios were 90.7% for the Company, 88.7%
15 for the Gas Group, and 82.8% for the S&P Public Utilities. The Company's operating
16 ratios were not appreciably different from the Gas Group.

17 Coverage. The level of fixed charge coverage (i.e., the multiple by which
18 available earnings cover fixed charges, such as interest expense) provides an
19 indication of the earnings protection for creditors. Higher levels of coverage, and
20 hence earnings protection for fixed charges, are usually associated with superior
21 grades of creditworthiness. Excluding Allowance for Funds Used During Construction
22 ("AFUDC"), the five-year average pre-tax interest coverage was 3.52 times for the
23 Company, 4.33 times for the Gas Group, and 3.19 times for the S&P Public Utilities.
24 The average interest coverages were highest for the Gas Group, followed by CPA and

²The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

1 the S&P Public Utilities. Recently, the pre-tax interest coverages for the Company
2 have declined due to the large tax credits in 2010 and 2011.

3 Quality of Earnings. Measures of earnings quality usually are revealed by the
4 percentage of AFUDC related to income available for common equity, the effective
5 income tax rate, and other cost deferrals. These measures of earnings quality usually
6 influence a firm's internally generated funds because poor quality of earnings would
7 not generate high levels of cash flow. Quality of earnings has not been a significant
8 concern for the Company, the Gas Group and the S&P Public Utilities.

9 Internally Generated Funds. Internally generated funds ("IGF") provide an
10 important source of new investment capital for a utility and represent a key measure of
11 credit strength. Historically, the five-year average percentage of IGF to capital
12 expenditures was 83.7% for the Company, 106.4% for the Gas Group and 93.0% for
13 the S&P Public Utilities. In recent years, the IGF to construction percentage for CPA
14 has lagged that of the Gas Group.

15 Betas. The financial data that I have been discussing relate primarily to
16 company-specific risks. Market risk for firms with publicly-traded stock is measured by
17 beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk
18 associated with changes in the overall market for common equities.³ Value Line
19 publishes such a statistical measure of a stock's relative historical volatility to the rest
20 of the market. A comparison of market risk is shown by the Value Line beta of 0.67 as
21 the average for the Gas Group (see page 2 of Schedule 3) and 0.76 as the average for
22 the S&P Public Utilities (see page 3 of Schedule 4).

23 **Q. Please summarize your risk evaluation.**

³The procedure used to calculate the beta coefficient published by Value Line is described in Appendix H. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

1 A. In several aspects, principally related to its smaller size, its more variable equity
2 returns, and its lower IGF to construction, CPA's risk is higher than the Gas Group.
3 The bond rating of NiSource, the Company's ultimate parent, is well below that of the
4 Gas Group, which indicates higher credit quality risk. Its common equity ratio and
5 operating ratio has been fairly similar to the Gas Group. On balance, the cost of equity
6 measured with the Gas Group data will provide an understatement of the Company's
7 cost of equity.

8 **CAPITAL STRUCTURE RATIOS**

9 **Q. Please explain the selection of capital structure ratios for CPA.**

10 A. In this case, the capital structure ratios of CPA have been proposed to calculate the
11 rate of return. Although the Company's long-term debt is provided by an affiliate, I will
12 show that the Company's capital structure ratios proposed in this case are reasonable.
13 Furthermore, consistency requires that the embedded cost rate of the Company's
14 senior securities also be employed.

15 **Q. Does Schedule 5 provide the Company's capitalization and capital structure**
16 **ratios?**

17 A. Yes. Schedule 5 presents the Company's capitalization and related capital structure
18 ratios. The May 31, 2012 capitalization corresponds with the end of the historic test
19 year in this case. The May 31, 2013 capital structure is estimated at the end of the
20 future test year, and the June 30, 2014 capital structure is estimated at the end of the
21 fully forecasted rate year. Prior to the end of the fully forecasted rate year, the
22 Company plans to roll-over \$86.825 million of long-term debt and to issue \$51.175
23 million of new long-term debt.

24 **Q. How do the capital structure ratios compare for CPA and the Gas Group?**

25 A. I have verified the reasonableness of the Company's common equity ratio by
26 considering the historical comparison to the Gas Group and with analysts' forecasts,

1 which influence investor expectations. For the historical comparison, the Gas Group
2 had a 56.7% common equity ratio at year-end 2011 calculated without short-term debt.
3 My comparison of these ratios rests on a calculation without short-term debt because
4 the Company uses a twelve-month average for ratesetting purposes, while the GAAP
5 financial reports for the Gas Group use fiscal year-end balances of short-term debt.
6 For the Company, its FFRY common equity ratio is 54.3% (\$509,276,000 ÷
7 \$938,666,000) computed without short-term debt. By comparison, the Gas Group had
8 a 56.7% common equity ratio, thereby indicating that the Company's common equity
9 ratio is reasonable. I have also compared the Company's proposed common equity
10 ratio to that of the Gas Group based upon forecast data widely available to investors
11 from Value Line. In the case of the Value Line forecasts, the common equity ratios are
12 computed without regard to short-term debt. Those ratios are:

Company	2012	2013	2014-17
AGL Resources, Inc.	50.0%	52.0%	57.0%
Atmos Energy Corporation	53.5%	51.5%	51.0%
Laclede Group, Inc.	64.0%	66.0%	69.0%
New Jersey Resources Corp.	59.5%	60.5%	66.5%
Northwest Natural Gas Co.	55.0%	57.0%	63.0%
Piedmont Natural Gas Company	57.0%	53.5%	50.0%
South Jersey Industries, Inc.	61.5%	62.5%	62.5%
Southwest Gas Corporation	54.0%	55.5%	53.0%
WGL Holdings, Inc.	67.5%	68.5%	70.5%
Average	58.0%	58.6%	60.3%

Source: The Value Line Investment Survey, June 8, 2012

13 These forecasts show that the 54.3% common equity ratio for CPA, which excludes
14 short-term debt, is reasonable by reference to the average ratios of the Gas Group.

15 **Q. What capital structure ratios do you recommend be adopted for rate of return**
16 **purposes in this proceeding?**

17 A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect known

or reasonably foreseeable changes which will occur during the course of the fully forecasted rate year. As a result, I will adopt the Company's fully forecast rate year capital structure ratios of 44.11% long-term debt, 3.57% short-term debt and 52.32% common equity. For short-term debt, I have used a twelve-month average for the fully forecasted rate year. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

COSTS OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of CPA's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of debt at May 31, 2012. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of debt at May 31, 2013. And on page 3 of Schedule 6, the embedded cost of debt is shown at June 30, 2014. For the new issues of long-term debt, I have used an estimated cost of 5.45% for the issue in November 2012, 5.50% for the issue in May 2013, and 5.55% for the issues in December 2013 and June 2014.

I will adopt the 5.80% embedded cost of long-term debt at June 30, 2014, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 44.11% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. I have used a cost of short-term debt of 1.90%, which represents the Company's estimate for the fully forecast rate year. The Company obtains its short-term debt from the NiSource money pool, which has a credit facility with a syndicate of banks. The interest rate is established as the one-month LIBOR plus 147.5 basis points. Hence,

the Company's estimate is comprised of the 0.42% LIBOR plus the spread, i.e., 0.42% + 1.475% = 1.895%, or rounded to 1.90%.

Q. What overall debt cost rate have you determined for rate of return purposes?

A. As shown on page 3 of Schedule 6, the combined cost of long- and short-term debt is 5.51% for the fully forecast rate year.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for CPA.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPA, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.0% to 11.3% for CPA. As explained previously, from this range I propose a rate of return on common equity of 11.25% in recognition of the exemplary performance of the Company's management.

DISCOUNTED CASH FLOW ANALYSIS

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Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process where, as in this case, the firm's market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended July 2012, the monthly dividend yields of the Gas Group are shown graphically on Schedule 7. The monthly dividend yields shown on Schedule 7 reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-

1 dividend date (i.e., the date by which a shareholder must own the shares to be entitled
2 to the dividend payment – usually about two to three weeks prior to the actual
3 payment). An explanation of this adjustment is provided in Appendix E.

4 For the twelve months ended July 2012, the average dividend yield was 3.71%
5 for the Gas Group based upon a calculation using annualized dividend payments and
6 adjusted month-end stock prices. The dividend yields for the more recent six- and
7 three-month periods were 3.79% and 3.78%, respectively. I have used, for the
8 purpose of my direct testimony, the six-month average dividend yield of 3.79% for the
9 Gas Group. The use of this dividend yield will reflect current capital costs, while
10 avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield
11 must be adjusted to reflect the prospective nature of the dividend payments i.e., the
12 higher expected dividends for the future. Recall that the DCF is an expectational
13 model that must reflect investor anticipated cash flows for the Gas Group. I have
14 adjusted the six-month average dividend yield in three different, but generally accepted
15 manners, and used the average of the three adjusted values as calculated in Appendix
16 E. That adjusted dividend yield is 3.90% for the Gas Group.

17 **Q. Please explain the underlying factors that influence investor's growth**
18 **expectations.**

19 A. As noted previously, investors are interested principally in the future growth of their
20 investment (i.e., the price per share of the stock). As I explain in Appendix E, future
21 earnings per share growth represent the DCF model's primary focus because under
22 the constant price-earnings multiple assumption of the model, the price per share of
23 stock will grow at the same rate as earnings per share. In conducting a growth rate
24 analysis, a wide variety of variables can be considered when reaching a consensus of
25 prospective growth, including: earnings, dividends, book value, and cash flow stated
26 on a per share basis. Historical values for these variables can be considered, as well

1 as analysts' forecasts that are widely available to investors. A fundamental growth
2 rate analysis also can be formulated, which consists of internal growth (" $b \times r$ "), where
3 " r " represents the expected rate of return on common equity and " b " is the retention
4 rate that consists of the fraction of earnings that are not paid out as dividends. The
5 internal growth rate can be modified to account for sales of new common stock -- this
6 is called external growth (" $s \times v$ "), where " s " represents the new common shares
7 expected to be issued by a firm and " v " represents the value that accrues to existing
8 shareholders from selling stock at a price different from book value. Fundamental
9 growth, which combines internal and external growth, provides an explanation of the
10 factors that cause book value per share to grow over time.

11 Growth also can be expressed in multiple stages. This expression of growth
12 consists of an initial "growth" stage where a firm enjoys rapidly expanding markets,
13 high profit margins, and abnormally high growth in earnings per share. Thereafter, a
14 firm enters a "transition" stage where fewer technological advances and increased
15 product saturation begin to reduce the growth rate and profit margins come under
16 pressure. During the "transition" phase, investment opportunities begin to mature,
17 capital requirements decline, and a firm begins to pay out a larger percentage of
18 earnings to shareholders. Finally, the mature or "steady-state" stage is reached when
19 a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where
20 they remain for the life of a firm. The three stages of growth assume a step-down of
21 high initial growth to lower sustainable growth. Even if these three stages of growth
22 can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to
23 remain fixed in perpetuity, represents an unrealistic expectation because the three
24 stages of growth can be repeated. That is to say, the stages can be repeated where
25 growth for a firm ramps-up and ramps-down in cycles over time.

1 **Q. What investor-expected growth rate is appropriate in a DCF calculation?**

2 A. Investors consider both company-specific variables and overall market sentiment (i.e.,
3 level of inflation rates, interest rates, economic conditions, etc.) when balancing their
4 capital gains expectations with their dividend yield requirements. I follow an approach
5 that is not rigidly formatted because investors are not influenced by a single set of
6 company-specific variables weighted in a formulaic manner. Therefore, in my opinion,
7 all relevant growth rate indicators using a variety of techniques must be evaluated
8 when formulating a judgment of investor-expected growth.

9 **Q. What data for the proxy group have you considered in your growth rate**
10 **analysis?**

11 A. I have considered the growth in the financial variables shown on Schedules 8 and 9.
12 The bar graph provided on Schedule 8 shows the historical growth rates in earnings
13 per share, dividends per share, book value per share, and cash flow per share for the
14 Gas Group. The historical growth rates were taken from the Value Line publication
15 that provides these data. As shown on Schedule 8, the historical growth of earnings
16 per share was in the range of 5.22% to 6.39% for the Gas Group.

17 Schedule 9 provides projected earnings per share growth rates taken from
18 analysts' forecasts compiled by IBES/First Call, Reuters, Zacks, Morningstar, and
19 Value Line. IBES/First Call, Reuters, Zacks, and Morningstar represent reliable
20 authorities of projected growth upon which investors rely. The IBES/First Call,
21 Reuters, Zacks, and Morningstar forecasts are limited to earnings per share growth,
22 while Value Line makes projections of other financial variables. The Value Line
23 forecasts of dividends per share, book value per share, and cash flow per share have
24 also been included on Schedule 9 for the Gas Group.

25 Although five-year forecasts usually receive the most attention in the growth
26 analysis for DCF purposes, current market performance is strongly influenced by

1 short-term earnings forecasts. Each of the major publications provides earnings
2 forecasts for the current and subsequent year. These short-term earnings forecasts
3 receive prominent coverage and, indeed, they dominate these publications.

4 **Q. Is a five-year investment horizon associated with the analysts' forecasts**
5 **consistent with the DCF model?**

6 A. Yes. Rather than viewing the DCF in the context of an endless stream of growing
7 dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital
8 appreciation, or capital gains yield) is most relevant to investors' total return
9 expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend
10 that can be discounted along with the annual dividend receipts during the investment-
11 holding period to arrive at the investor-expected return. The growth in the price per
12 share will equal the growth in earnings per share absent any change in price-earnings
13 ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific
14 growth analysis, which focuses principally upon five-year forecasts of earnings per
15 share growth, is consistent with the type of analysis that influences the total return
16 expectation of investors. Moreover, academic research focuses on five-year growth
17 rates as they influence stock prices. Indeed, if investors really required forecasts
18 which extended beyond five years in order to properly value common stocks, then I am
19 sure that some investment advisory service would begin publishing that information for
20 individual stocks in order to meet the demands of investors. The absence of such a
21 publication signals that investors do not require infinite forecasts in order to purchase
22 and sell stocks in the marketplace.

23 **Q. What specific evidence have you considered in the DCF growth analysis?**

24 A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected
25 earnings per share growth rates for the Gas Group are 4.89% by IBES/First Call,
26 4.80% by Reuters, 4.53% by Zacks, 5.88% by Morningstar, and 4.94% by Value Line.

The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 4.94%) than the dividends per share (i.e., 4.00%), which translates into a declining dividend payout ratio for the future. As noted earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts. Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investor expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments, and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must

1 be placed upon projected earnings per share growth. In this regard, it is worthwhile to
2 note that Professor Myron Gordon, the foremost proponent of the DCF model in rate
3 cases, concluded that the best measure of growth in the DCF model is a forecast of
4 earnings per share growth.⁴ Hence, to follow Professor Gordon's findings, projections
5 of earnings per share growth, such as those published by IBES/First Call, Reuters, and
6 Zacks, and Value Line, represent a reasonable assessment of investor expectations.

7 It is appropriate to consider all forecasts of earnings growth rates that are
8 available to investors. In this regard, I have considered the forecasts from IBES/First
9 Call, Reuters, Zacks, Morningstar, and Value Line. The IBES/First Call, Reuters,
10 Zacks, and Morningstar growth rates are consensus forecasts taken from a survey of
11 analysts that make projections of growth for these companies. The IBES/First Call,
12 Reuters, Zacks, and Morningstar estimates are obtained from the Internet and are
13 widely available to investors free-of-charge. First Call probably is quoted most
14 frequently in the financial press when reporting on earnings forecasts. The Value Line
15 forecasts also are widely available to investors and can be obtained by subscription or
16 free-of-charge at most public and collegiate libraries.

17 The forecasts of earnings per share growth, as shown on Schedule 9, provide
18 a range of growth rates of 4.53% to 5.88%. Although the DCF growth rates cannot be
19 established solely with a mathematical formulation, it is my opinion that an investor-
20 expected growth rate of 5.25% is within the array of earnings per share growth rates
21 shown by the analysts' forecasts. The Value Line forecast of dividend per share
22 growth is inadequate in this regard due to the forecasted decline in the dividend payout
23 ratio. Moreover, the restructuring and consolidation now taking place in the utility
24 industry will provide additional risks and opportunities as the utility industry

⁴"Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould.

1 successfully adapts to the new business environment. These changes in growth
2 fundamentals will undoubtedly develop beyond the next five years typically considered
3 in the analysts' forecasts, and will enhance the growth prospects for the future. In my
4 opinion, a 5.25% growth rate will accommodate all these factors considering that
5 analysis growth forecasts are currently depressed. In adopting a 5.25% growth rate
6 for DCF, I have recognized that the forecasts today are depressed when viewed in the
7 context of historical growth and that there is a certain element of circularity to the
8 growth rate analysis which leads today's forecast to be understated.

9 **Q. Are the dividend yield and growth components of the DCF adequate to explain**
10 **the rate of return on common equity when it is used in the calculation of the**
11 **weighted average cost of capital?**

12 A. Only if the capital structure ratios are measured with the market value of debt and
13 equity. If book values are used to compute the capital structure ratios, then an
14 adjustment is required.

15 **Q. Please explain why.**

16 A. If regulators use the results of the DCF (which are based on the market price of the
17 stock of the companies analyzed) to compute the weighted average cost of capital
18 based on a book value capital structure used for ratesetting purposes, the utility will
19 not, by definition, recover its risk-adjusted capital cost. This is because market
20 valuations of equity are based on market value capital structures, which in general
21 have more equity and less debt and therefore reflect less risk than book value capital
22 structures. The utility's risk-adjusted cost of equity will necessarily be lower with the
23 market value capital structure than it is relative to the book value capital structure. The
24 difference represents that portion of the utility's cost of equity that it will not recover
25 unless either the market value cost of equity is applied to the utility's market value
26 capital structure or it is adjusted to reflect the higher risk associated with the book

1 value capital structure. By the same token, if the utility's market value capital structure
2 is less than its book value structure, then the utility's market cost of equity should be
3 adjusted downward to reflect the lower risk associated with the book value capital
4 structure, or else the utility will over-recover its total cost of equity.

5 This shortcoming of the DCF has persuaded the Commission to adjust the DCF
6 determined cost of equity upward to make the return consistent with the book value
7 capital structure. Specific adjustments to recognize this risk difference were made in
8 the following cases:

- 9 • January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-
10 00016339 -- 60 basis points adjustment.
- 11 • August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-
12 00016750 -- 80 basis points adjustment.
- 13 • January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-
14 00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis
15 points adjustment.
- 16 • August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis
17 points adjustment.
- 18 • December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-
19 00049255 -- 45 basis points adjustment.
- 20 • February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398 -- 70
21 basis points adjustment.

22
23 In order to make the DCF results relevant to the capitalization measured at book value
24 (as is done for rate setting purposes); the market-derived cost rate cannot be used
25 without modification.

26 **Q. Is your leverage adjustment dependent upon the market valuation or book**
27 **valuation from an investor's perspective?**

28 A. The only perspective that is important to investors is the return that they can realize on
29 the market value of their investment. As I have measured the DCF, the simple yield
30 (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an
31 investor is willing to pay for a share of stock. The DCF formula is derived from the
32 standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of
33 equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar

DCF equation: $k = D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. Multiple terms are used in the case of debt and preferred stock.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations regarding market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment

1 that I propose is based on the fundamental financial precept that the cost of equity is
2 equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return
3 equates to the cost of equity with a capital structure that contains 100% equity) plus
4 the additional return required for introducing debt and/or preferred stock leverage into
5 the capital structure.

6 Further, as noted previously, the high market prices of utility stocks cannot be
7 attributed solely to the notion that these companies are expected to earn a return on
8 equity that differs from its cost of equity. Stock prices above book value are common
9 for utility stocks and, indeed, the stock prices of non-regulated companies exceed
10 book values by even greater margins. In this regard, according to the Barron's issue
11 of August 20, 2012, the major market indices' market-to-book ratios are well above
12 unity. The Dow Jones Utility index traded at a multiple of 1.78 times book value, which
13 is below the market multiple of other indices. For example, the S&P Industrial index
14 was at 3.00 times book value and the Dow Jones Industrial index was at 2.90 times
15 book value. It is difficult to accept that the vast majority of all firms operating in our
16 economy are generating returns far in excess of their cost of capital. Certainly, in our
17 free-market economy, competition should contain such "excesses" if they indeed exist.

18 Finally, the leverage adjustment adds stability to the final DCF cost rate. That
19 is to say, as the market capitalization increases relative to its book value, the leverage
20 adjustment increases while the simple yield (D/P) plus growth (g) result declines. The
21 reverse also is true that when the market capitalization declines, the leverage
22 adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

23 **Q. How is the DCF-determined cost of equity adjusted for the financial risk**
24 **associated with the book value of the capitalization?**

25 A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories
26 about the role of leverage in a firm's capital structure. As part of that work, Modigliani

1 and Miller established that, as the borrowing of a firm increases, the expected return
2 on stockholders' equity also increases.⁵ This principle is incorporated into my leverage
3 adjustment which recognizes that the expected return on equity increases to reflect the
4 increased risk associated with the higher financial leverage shown by the book value
5 capital structure, as compared to the market value capital structure that contains lower
6 financial risk. Modigliani and Miller proposed several approaches to quantify the equity
7 return associated with various degrees of debt leverage in a firm's capital structure.
8 These formulas point toward an increase in the equity return associated with the
9 higher financial risk of the book value capital structure. Simply stated, the leverage
10 adjustment contains no factor for a particular market-to-book ratio. It merely
11 expresses the cost of equity as the unleveraged return plus compensation for the
12 additional risk of introducing debt and/or preferred stock into the capital structure.
13 There can be no dispute that a firm's financial risk varies with the relative amount of
14 leverage contained in its capital structure. As detailed in Appendix E, the Modigliani
15 and Miller theory when applied to the Gas Group shows that the cost of equity
16 increases by 0.64% (9.79% - 9.15%) when the book value of equity, rather than the
17 market value of equity, is used for ratesetting purposes.

18 **Q. Is the leverage adjustment that you propose designed to transform the market**
19 **return into one that is designed to produce a particular market-to-book ratio?**

20 A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a
21 convenient way of showing the amount that must be added to (or subtracted from) the
22 result of the simple DCF model (i.e., $D/P + g$), in the context of a return that applies to
23 the capital structure used in ratemaking, which is computed with book value weights

⁵ Modigliani, F. and Miller, M.H. "The Cost of Capital, Corporation Finance, and the Theory of Investments." American Economic Review, June 1958, 261-297.

Modigliani, F. and Miller, M. H. "Taxes and the Cost of Capital: A Correction." American Economic Review, June 1963, 433-443.

1 rather than market value weights, in order to arrive at the utility's total cost of equity. I
2 specify a separate factor, which I call the leverage adjustment, but there is no need to
3 do so other than providing identification for this factor. If I expressed my return solely
4 in the context of the book value weights that we use to calculate the weighted average
5 cost of capital, and ignore the familiar $D/P + g$ expression entirely, then there would be
6 no separate element to reflect the financial leverage change from market value to book
7 value capitalization. This is because the equity return applicable to the book value
8 common equity ratio is equal to 7.94%, which is the return for the Gas Group
9 applicable to its equity with no debt in its capital structure (i.e., the cost of capital is
10 equal to the cost of equity with a 100% equity ratio) plus 1.84% compensation for
11 having a 43.21% debt ratio, plus 0.01% for having a 0.17% preferred stock ratio (see
12 pages E-11 and E-12 of Appendix E). The sum of the parts is 9.79% (7.94% + 1.84%
13 + 0.01%) and there is no need to even address the cost of equity in terms of $D/P + g$.
14 To express this same return in the context of the familiar DCF model, I summed the
15 3.90% dividend yield, the 5.25% growth rate, and the 0.64% for the leverage
16 adjustment in order to arrive at the same 9.79% (3.90% + 5.25% + 0.64%) return. I
17 know of no means to mathematically solve for the 0.64% leverage adjustment by
18 expressing it in the terms of any particular relationship of market price to book value.
19 The 0.64% adjustment is merely a convenient way to compare the 9.79% return
20 computed directly with the Modigliani & Miller formulas to the 9.15% return generated
21 by the DCF model based on a market value capital structure. My point is that when we
22 use a market-determined cost of equity developed from the DCF model, it reflects a
23 level of financial risk that is different (in this case, lower) from the capital structure
24 stated at book value. This process has nothing to do with targeting any particular
25 market-to-book ratio.

1 **Q. Please provide the DCF return based upon your preceding discussion of**
2 **dividend yield, growth, and leverage.**

3 A. As explained previously, I have utilized a six-month average dividend yield (" D_1 / P_0 ")
4 adjusted in a forward-looking manner for my DCF calculation. This dividend yield is
5 used in conjunction with the growth rate (" g ") previously developed. The DCF also
6 includes the leverage modification ("lev.") required when the book value equity ratio is
7 used in determining the weighted average cost of capital in the ratesetting process
8 rather than the market value equity ratio related to the price of stock.

$$D_1/P_0 + g + lev. = k$$

$$\text{Gas Group} \quad 3.90\% + 5.25\% + 0.64\% = 9.79\%$$

9 The DCF result shown above represents the simplified (i.e., Gordon) form of the
10 model that contains a constant growth assumption. I should reiterate, however, that
11 the DCF-indicated cost rate provides an explanation of the rate of return on common
12 stock market prices without regard to the prospect of a change in the price-earnings
13 multiple. An assumption that there will be no change in the price-earnings multiple is
14 not supported by the realities of the equity market, because price-earnings multiples
15 do not remain constant. This is one of the constraints of this model that makes it
16 important to consider other model results when determining a company's cost of
17 equity. For this reason, the DCF cost rate I have developed for the Gas Group
18 understates the cost of equity. As noted previously, CPA has weaker credit quality as
19 compared to the Gas Group. A generally accepted tenet of corporate finance is that
20 risk and return are linked. Here, weaker credit quality adds to risk. As a consequence,
21 an upward adjustment to the DCF results is required to accommodate the risk of CPA
22 vis-à-vis the Gas Group.

1 **Q. Can an adjustment to the DCF results for the Gas Group be justified regarding**
2 **weaker credit quality of CPA?**

3 A. Yes. The DCF returns that are produced for the Gas Group relate to the average
4 credit quality of that group. In addition, the Company's forecast common equity ratio
5 comes up short as compared to the common equity ratios of the Gas Group. This fact
6 further supports an adjustment to the DCF results of the Gas Group as they apply to
7 CPA. In order to provide some recognition of the additional return that is required to
8 compensate CPA for its higher risk in this regard, I have reviewed the difference in
9 yields on A-rated and Baa-rated public utility debt. The yield difference is related to
10 the additional return required when risk increases, i.e., generally bond yields increase
11 as credit quality declines. The yield difference between A-rated and Baa-rated public
12 utility bonds is used as a proxy for quantifying this additional risk.

13 As shown by the data presented on page 2 of Schedule 10, the difference in
14 yields between A-rated and Baa-rated public utility bonds was 0.76% (5.00% - 4.24%)
15 for the six-months ended July 2012. This yield difference can be added to the DCF
16 calculation for the Gas Group to provide some recognition of the higher risk of CPA
17 due to its weaker credit quality risk. As such, the DCF return requires adjustment to
18 10.55% (9.79% + 0.76%) to recognize the higher risk of CPA.

19 RISK PREMIUM ANALYSIS

20 **Q. Please describe your use of the risk premium approach to determine the cost of**
21 **equity.**

22 A. The details of my use of the Risk Premium approach and the evidence in support of
23 my conclusions are set forth in Appendix G. I will summarize them here. With this
24 method, the cost of equity capital is determined by corporate bond yields plus a
25 premium to account for the fact that common equity is exposed to greater investment
26 risk than debt capital. As with other models used to determine the cost of equity, the

1 Risk Premium approach has its limitations, including potential imprecision in the
2 assessment of the future cost of corporate debt and the measurement of the risk-
3 adjusted common equity premium.

4 **Q. What long-term public utility debt cost rate did you use in your risk premium**
5 **analysis?**

6 A. In my opinion, a 4.75% yield represents a reasonable estimate of the prospective yield
7 on long-term A-rated public utility bonds. The Moody's index and the Blue Chip
8 forecasts support this figure. The historical yields for long-term public utility debt are
9 shown graphically on page 1 of Schedule 10. For the twelve months ended July 2012,
10 the average monthly yield on Moody's A-rated index of public utility bonds was 4.34%.
11 For the six and three-month periods ended July 2012, the yields were 4.24% and
12 4.07%, respectively. During the twelve-months ended July 2012, the range of the
13 yields on A-rated public utility bonds was 3.93% to 4.69%.

14 **Q. What forecasts of interest rates have you considered in your analysis?**

15 A. I have determined the prospective yield on A-rated public utility debt by using the Blue
16 Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I
17 describe above and in Appendix F. The Blue Chip is a reliable authority and contains
18 consensus forecasts of a variety of interest rates compiled from a panel of banking,
19 brokerage, and investment advisory services. In early 1999, Blue Chip stopped
20 publishing forecasts of yields on A-rated public utility bonds because the Federal
21 Reserve deleted these yields from its Statistical Release H.15. To independently
22 project a forecast of the yields on A-rated public utility bonds, I have combined the
23 forecast yields on long-term Treasury bonds published on August 1, 2012, and a yield
24 spread of 1.50%. As shown on page 5 of Schedule 10, the yields on A-rated public
25 utility bonds have exceeded those on Treasury bonds by 1.62% on a twelve-month
26 average basis, 1.65% on a six-month average basis, and 1.72% on a the three-month

1 average basis. From these averages, 1.50% represents a reasonable spread for the
2 yield on A-rated public utility bonds over Treasury bonds. For comparative purposes, I
3 also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds.
4 These forecasts are:

Year	Quarter	Blue Chip Financial Forecasts			A-rated Public Utility	
		Corporate		30-Year	Spread	Yield
		Aaa-rated	Baa-rated	Treasury		
2012	Third	3.5%	4.9%	2.6%	1.50%	4.10%
2012	Fourth	3.6%	4.9%	2.8%	1.50%	4.30%
2013	First	3.7%	5.0%	2.9%	1.50%	4.40%
2013	Second	3.9%	5.1%	3.1%	1.50%	4.60%
2013	Third	4.1%	5.2%	3.2%	1.50%	4.70%
2013	Fourth	4.2%	5.4%	3.4%	1.50%	4.90%

5 **Q. Are there additional forecasts of interest rates that extend beyond those shown**
6 **above?**

7 A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its
8 June 1, 2012 publication, the Blue Chip published longer-term forecasts of interest
9 rates, which were reported to be:

Averages	Blue Chip Financial Forecasts		
	Corporate		30-Year
	Aaa-rated	Baa-rated	Treasury
2014-18	5.8%	6.8%	5.1%
2019-23	6.2%	7.2%	5.5%

10 Given these forecasted interest rates, a 4.75% yield on A-rated public utility bonds
11 represents a reasonable expectation given the current forecasts that suggest rising
12 interest rates.

13 **Q. What equity risk premium have you determined for public utilities?**

14 A. Appendix G provides a discussion of the financial returns that I relied upon to develop
15 the appropriate equity risk premium for the S&P Public Utilities. I have calculated the
16 equity risk premium by comparing the market returns on utility stocks and the market

1 returns on utility bonds. I chose the S&P Public Utility index for the purpose of
2 measuring the market returns for utility stocks. The S&P Public Utility index is
3 reflective of the risk associated with regulated utilities, rather than some broader
4 market indexes, such as the S&P 500 Composite index. The S&P Public Utility index
5 is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility
6 index reduces the role of judgment in establishing the risk premium for public utilities.
7 With the equity risk premiums developed for the S&P Public Utilities as a base, I
8 derived the equity risk premium for the Gas Group.

9 **Q. What equity risk premium for the S&P Public Utilities have you determined for**
10 **this case?**

11 A. To develop an appropriate risk premium, I analyzed the results for the S&P Public
12 Utilities by averaging (i) the midpoint of the range shown by the geometric mean and
13 median and (ii) the arithmetic mean. This procedure has been employed to provide a
14 comprehensive way of measuring the central tendency of the historical returns. As
15 shown by the values set forth on page 2 of Schedule 11, the indicated risk premiums
16 for the various time periods analyzed are 5.51% (1928-2007), 6.58% (1952-2007),
17 6.08% (1974-2007), and 6.37% (1979-2007). The selection of the shorter periods
18 taken from the entire historical series is designed to provide a risk premium that
19 conforms more nearly to present investment fundamentals, and removes some of the
20 more distant data from the analysis.

21 **Q. Do you have further support for the selection of the time periods used in your**
22 **equity risk premium determination?**

23 A. Yes. First, the terminal year of my analysis presented in Schedule 11 represents the
24 returns realized through 2007. An update to 2011 has not been prepared because of
25 the difficulty in obtaining the return on public utility bonds from Lehman Brothers. In
26 the last case, other parties were critical that by using data that stopped in 2007, we

were missing the large negative returns on stocks during the financial crisis, as well as the recovery following the resolution of the financial crisis. Today, these returns have nearly offset. Indeed the cumulative return for 2008, 2009, 2010 and 2011 were just -1.6%. As another demonstration of this point, the SBBI large company stock returns were 12.3% for 1926 to 2007, as compared to 11.8% for 1926 to 2011. Indeed as of August 20, 2012, many of the major stock indices have recovered to within 92% ($1418.16 \div 1549.38$ for the S&P 500 Composite Index) of the peak level prior to financial crisis. Hence, the fall and rebound in stock prices after 2007 indicate that the cumulative returns up to 2007 continue to be relevant today in measuring the common equity risk premium. Second, the selection of the initial year of each period was based upon the financial market defining events that I note here and describe in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. I consistently use these periods in my work, and additional data are merely added to the earlier results when they become available. The periods chosen are, therefore, not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 11, the 1928-2007 period provides the lowest indicated risk premium, while the 1952-2007 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 6.23% ($6.08\% + 6.37\% = 12.45\% \div 2$) is derived by averaging

1 data covering the periods 1974-2007 and 1979-2007. Therefore, 6.23% represents a
2 reasonable risk premium for the S&P Public Utilities in this case.

3 As noted earlier in my fundamental risk analysis, differences in risk
4 characteristics must be taken into account when applying the results for the S&P
5 Public Utilities to the Gas Group. I recognized these differences in the development of
6 the equity risk premium in this case. I previously enumerated various differences in
7 fundamentals between the Gas Group and the S&P Public Utilities, including size,
8 market ratios, common equity ratio, return on book equity, operating ratios, coverage,
9 quality of earnings, internally generated funds, and betas. In my opinion, these
10 differences indicate that 5.50% represents a reasonable common equity risk premium
11 in this case. This represents approximately 88% ($5.50\% \div 6.23\% = 0.88$) of the risk
12 premium of the S&P Public Utilities, and is reflective of the risk of the Gas Group
13 compared to the S&P Public Utilities. I should note further that the flight to safety,
14 which has depressed interest rates, has produced a two-fold impact on capital costs.
15 This aversion to risk has both depressed interest rates and has also increased the risk
16 premium associated with owning stocks versus holding bonds. Therefore, in today's
17 environment risk premiums are higher than historically due to a lack of confidence that
18 has increased the compensation for risk taking.

19 **Q. What common equity cost rate did you determine based on your risk premium**
20 **analysis?**

21 A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-
22 term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk
23 Premium approach provides a cost of equity of:

$$i + RP = k$$
$$\text{Gas Group} \quad 4.75\% + 5.50\% = 10.25\%$$

As I noted previously, NiSource carries a Baa3/BBB- rating on its debt. This means that the Risk Premium cost rate shown above would understate the Company's cost of equity by 0.76% (5.00% - 4.24%), because the 10.25% shown above is based on the yield on A-rated public utility debt. As such, the Risk Premium cost rate for CPA is 11.01% (10.25% + 0.76%). I should note that the effective interest rate that I used in the Risk Premium analysis was 5.51% (4.75% + 0.76%) for Baa-rated public utility bonds. Such rate is consistent with the forecast interest rates for the Company's debt issues in the FFRY.

CAPITAL ASSET PRICING MODEL

Q. Have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. Yes. As with other models of the cost of equity, the CAPM contains a variety of assumptions and shortcomings that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will help reduce the unavoidable defects found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("R_f"), the beta measure of systematic risk ("β"), and the market risk premium ("R_m-R_f") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM, it

is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors, because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity, because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 12, the average beta is 0.67 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,⁶ as follows:

$$\beta_l = \beta_u [1 + (1 - t) D/E + P/E]$$

where β_l = the leveraged beta, β_u = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and, therefore, are related to the market value capitalization. By using the formula shown

⁶ Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452

1 above and the capital structure ratios measured at market value, the beta would
2 become 0.50 for the Gas Group if it employed no leverage and was 100% equity
3 financed. With the unleveraged beta as a base, I calculated the leveraged beta of 0.75
4 for the book value capital structure of the Gas Group. The betas and corresponding
5 common equity ratios are:

<u>Beta</u>	<u>Common Equity Ratio</u>	<u>Beta</u>	<u>Common Equity Ratio</u>
0.67	66.34%	0.75	56.62%

6 The book value leveraged beta that I will employ in the CAPM cost of equity is 0.75 for
7 the Gas Group.

8 **Q. What risk-free rate have you used in the CAPM?**

9 A. As shown on pages 2 and 3 of Schedule 12, I provided the historical yields on
10 Treasury notes and bonds. For the twelve months ended July 2012, the average yield
11 on 30-year Treasury bonds was 3.07%, as shown on page 3 of that schedule. For the
12 six- and three-months ended July 2012, the yields on 30-year Treasury bonds were
13 2.97% and 2.74%, respectively. During the twelve-months ended July 2012, the range
14 of the yields on 30-year Treasury bonds was 2.59% to 3.65%. During the past
15 months, there has been a significant decline in the yields on Treasury obligations,
16 which can be traced to a number of factors, including: the sovereign debt crisis in the
17 euro zone, concern over a possible double dip recession, the potential for deflation,
18 and the Fed's maintenance of its large balance sheet through the reinvestment of the
19 proceeds from maturing mortgage-backed securities, the purchase of Treasury
20 obligations (also known as QE2), and the lengthening of the maturity of the Fed's bond
21 portfolio through the sale of short-term Treasuries and the purchase of Treasury
22 obligations (also known as operation twist). These factors have resulted in a crisis of
23 confidence that has produced a flight to safety, thus producing low interest rates. Low

1 interest rates have also been encouraged by policy decisions by the FOMC in
2 attempting to deal with stagnant job growth, which is part of its dual mandate. During
3 this period of extraordinarily low interest rates, the market premium has clearly
4 increased. As shown on page 4 of Schedule 12, forecasts published by Blue Chip
5 August 1, 2012 indicate that the yields on long-term Treasury bonds are expected to
6 be in the range of 2.6% to 3.4% during the next six quarters. The longer term
7 forecasts described previously (see Blue Chip Financial Forecast presented earlier)
8 show that the yields on 30-year Treasury bonds will average 5.1% from 2014 through
9 2018 and 5.5% from 2019 to 2023. For the reasons explained previously, forecasts of
10 interest rates should be emphasized at this time in selecting the risk-free rate of return
11 in CAPM. Hence, I have used a 3.25% risk-free rate of return for CAPM purposes,
12 which considers not only the Blue Chip forecasts, but also the recent trend in the yields
13 on long-term Treasury bonds.

14 **Q. What market premium have you used in the CAPM?**

15 A. As shown in Appendix H, the market premium is derived from the SBBI Classic
16 Yearbook (i.e., 6.16%) and the Value Line and S&P 500 returns (i.e., 11.81%). For the
17 historically based market premium, I have used the arithmetic mean. We can see that
18 expected market premiums are clearly higher than historical premiums as a result of
19 the flight to safety in Treasury obligations and a general aversion to risk that I
20 discussed previously. The market premium as averaged from these sources equals
21 8.99% ($6.16\% + 11.81\% = 17.97\% \div 2$).

22 **Q. Are there adjustments to the CAPM results that are necessary to fully reflect the**
23 **rate of return on common equity?**

24 A. Yes. The technical literature supports an adjustment relating to the size of the
25 company or portfolio for which the calculation is performed. As the size of a firm
26 decreases, its risk and, hence, its required return increases. Moreover, in his

discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of \$2,190 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.14%.

Q. What CAPM result have you determined?

A. Using the 3.25% risk-free rate of return, the leverage adjusted beta of 0.75 for the Gas Group, the 8.99% market premium, and the 1.14% size adjustment, I derived the following CAPM-indicated cost of equity:

$$R_f + \beta \times (R_m - R_f) + \text{size} = k$$
$$\text{Gas Group} \quad 3.25\% + 0.75 \times (8.99\%) + 1.14\% = 11.13\%$$

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of the Comparable Earnings approach are set forth in Appendix I. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings

1 approach should be companies whose prices are not subject to cost-based price
2 ceilings (i.e., non-regulated firms) so that circularity is avoided. There are two avenues
3 available to implement the Comparable Earnings approach. One method would
4 involve the selection of another industry (or industries) with comparable risks to the
5 public utility in question, and the results for all companies within that industry would
6 serve as a benchmark. The second approach requires the selection of parameters
7 that represent similar risk traits for the public utility and the comparable risk
8 companies. Using this approach, the business lines of the comparable companies
9 become unimportant. The latter approach is preferable with the further qualification
10 that the comparable risk companies exclude regulated firms in order to avoid the
11 circular reasoning implicit in the use of the achieved earnings/book ratios of other
12 regulated firms. The United States Supreme Court has held that:

13 A public utility is entitled to such rates as will permit it to
14 earn a return on the value of the property which it employs
15 for the convenience of the public equal to that generally
16 being made at the same time and in the same general part
17 of the country on investments in other business
18 undertakings which are attended by corresponding risks
19 and uncertainties.... The return should be reasonably
20 sufficient to assure confidence in the financial soundness
21 of the utility and should be adequate, under efficient and
22 economical management, to maintain and support its credit
23 and enable it to raise the money necessary for the proper
24 discharge of its public duties. Bluefield Water Works vs.
25 Public Service Commission, 262 U.S. 668 (1923).
26

27 Therefore, it is important to identify the returns earned by firms that compete for capital
28 with a public utility. This can be accomplished by analyzing the returns of non-
29 regulated firms that are subject to the competitive forces of the marketplace.

30 **Q. How have you implemented the Comparable Earnings approach?**

31 A. In order to implement the Comparable Earnings approach, non-regulated companies
32 were selected from The Value Line Investment Survey for Windows that have six
33 categories (see Appendix I for definitions) of comparability designed to reflect the risk

1 of the Gas Group. These screening criteria were based upon the range as defined by
2 the rankings of the companies in the Gas Group. The items considered were:
3 Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas,
4 and Technical Rank. The identities of the companies comprising the Comparable
5 Earnings group and their associated rankings within the ranges are identified on page
6 1 of Schedule 13.

7 Value Line data was relied upon because it provides a comprehensive basis for
8 evaluating the risks of the comparable firms. As to the returns calculated by Value
9 Line for these companies, there is some downward bias in the figures shown on page
10 2 of Schedule 13, because Value Line computes the returns on year-end rather than
11 average book value. If average book values had been employed, the rates of return
12 would have been slightly higher. Nevertheless, these are the returns considered by
13 investors when taking positions in these stocks. Because many of the comparability
14 factors, as well as the published returns, are used by investors in selecting stocks, and
15 to the extent that investors rely on the Value Line service to gauge returns, it is,
16 therefore, an appropriate database for measuring comparable return opportunities.

17 **Q. What data have you used in your Comparable Earnings analysis?**

18 A. I have used both historical realized returns and forecasted returns for non-utility
19 companies. As noted previously, I have not used returns for utility companies in order
20 to avoid the circularity that arises from using regulatory-influenced returns to determine
21 a regulated return. It is appropriate to consider a relatively long measurement period
22 in the Comparable Earnings approach in order to cover conditions over an entire
23 business cycle. A ten-year period (five historical years and five projected years) is
24 sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results
25 of the Comparable Earnings method can be applied directly to the book value
26 capitalization. In other words, the Comparable Earnings approach does not contain

the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 12.2% using only the returns that were less than 20% as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.2% also using values less than 20%, as provided on page 2 of Schedule 13.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

	<u>Historical</u>	<u>Forecast</u>	<u>Average</u>
Comparable Earnings Group	12.2%	13.2%	12.70%

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of the variety of methods and models described previously, I recommend that the Commission set the Company's rate of return on common equity at 11.25%. The proposed rate of return on common equity of 11.25% provides recognition of the exemplary performance of the Company's management and the high quality of service provided to its customers as explained in the testimony of Mr. Kempic. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 My studies and prepared direct testimony have been presented before thirty-six (36)
2 federal, state and municipal regulatory commissions, consisting of: the Federal Energy
3 Regulatory Commission; state public utility commissions in Alabama, Alaska, California,
4 Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky,
5 Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire,
6 New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South
7 Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas
8 Commission, and the Texas Commission on Environmental Quality. My testimony has been
9 offered in over 200 rate cases involving electric power, natural gas distribution and
10 transmission, resource recovery, solid waste collection and disposal, telephone, wastewater,
11 and water service utility companies. While my testimony has involved principally fair rate of
12 return and financial matters, I have also testified on capital allocations, capital recovery, cash
13 working capital, income taxes, factoring of accounts receivable, and take-or-pay expense
14 recovery. My testimony has been offered on behalf of municipal and investor-owned public
15 utilities and for the staff of a regulatory commission. I have also testified at an Executive
16 Session of the State of New Jersey Commission of Investigation concerning the BPU
17 regulation of solid waste collection and disposal.

18 I was a co-author of a verified statement submitted to the Interstate Commerce
19 Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-
20 author of comments submitted to the Federal Energy Regulatory Commission regarding the
21 Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986
22 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000).
23 Further, I have been the consultant to the New York Chapter of the National Association of
24 Water Companies, which represented the water utility group in the Proceeding on Motion of

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

1 the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-
2 0509). I have also submitted comments to the Federal Energy Regulatory Commission in its
3 Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission
4 Organizations and on behalf of the Edison Electric Institute in its intervention in the case of
5 Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of
6 the panel of participants at the Technical Conference in Docket No. PL07-2 on the
7 Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

8 In late 1978, I arranged for the private placement of bonds on behalf of an investor-
9 owned public utility. I have assisted in the preparation of a report to the Delaware Public
10 Service Commission relative to the operations of the Lincoln and Ellendale Electric Company.
11 I was also engaged by the Delaware P.S.C. to review and report on the proposed financing
12 and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-
13 79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection
14 Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

15 I have been a consultant to the Bucks County Water and Sewer Authority concerning
16 rates and charges for wholesale contract service with the City of Philadelphia. My municipal
17 consulting experience also included an assignment for Baltimore County, Maryland, regarding
18 the City/County Water Agreement for Metropolitan District customers (Circuit Court for
19 Baltimore County in Case 34/153/87-CSP-2636).

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

Traditional cost of service regulation, as implemented by a regulatory agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide the public utility and its investors with an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with customers has been changing, a regulated utility remains quite different from a non-regulated firm, which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,¹ several tests have been articulated through which the regulator can determine the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to

¹Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

1 provide adequate and reliable service to the public.

2 A fair rate of return must not only provide the utility with the ability to attract new capital
3 it must also be fair to existing investors. An appropriate rate of return which may have been
4 reasonable at one point in time may become too high or too low at a subsequent point in time,
5 based upon changing business risks, economic conditions and alternative investment
6 opportunities. When applying the standards of a fair rate of return, it must be recognized that
7 the end result must provide for the payment of interest on the company's debt, the payment of
8 dividends on the company's stock, the recovery of costs associated with securing capital, the
9 maintenance of reasonable credit quality for the company, and support of the company's
10 financial condition, which today would include those measures of financial performance in the
11 areas of interest coverage and adequate cash flow derived from a reasonable level of
12 earnings.

APPENDIX C TO DIRECT TESTIMONY OF PAUL R. MOUL

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms, which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings, which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources

APPENDIX C TO DIRECT TESTIMONY OF PAUL R. MOUL

of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk, which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

APPENDIX D TO DIRECT TESTIMONY OF PAUL R. MOUL

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation, which lacks such a basis, will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods, which have been employed to measure the cost of equity, include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns, which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the

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1 payment of interest and principal to creditors has priority over the payment of dividends and
2 return of capital to equity investors. Hence, equity investors require a higher rate of return
3 than the yield on long-term corporate bonds.

4 The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the
5 yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside
6 from the reliance on the risk-free rate of return, the CAPM gives specific quantification to
7 systematic (or market) risk as measured by beta.

8 The Comparable Earnings approach measures the returns expected/experienced by
9 other non-regulated firms and has been used extensively in rate of return analysis for over a
10 half century. However, its popularity diminished in the 1970s and 1980s with the
11 popularization of market-based models. Recently, there has been renewed interest in this
12 approach. Indeed, the financial community has expressed the view that the regulatory
13 process must consider the returns, which are being achieved in the non-regulated sector so
14 that public utilities can compete effectively in the capital markets. Indeed, with additional
15 competition being introduced throughout the traditionally regulated public utility industry,
16 returns expected to be realized by non-regulated firms have become increasingly relevant in the
17 ratesetting process. The Comparable Earnings approach considers directly those
18 requirements and it fits the established standards for a fair rate of return set forth in the
19 landmark decisions on the issue of rate of return. These decisions require that a fair return for
20 a utility must be equal to that earned by firms of comparable risk.

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DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = $\$100 \div (1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate, which reflects the risk or uncertainty, associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, K_p is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, K_p . In this circumstance:

$$P_0 = \frac{D_1}{(1 + K_p)} + \frac{D_2}{(1 + K_p)^2} + \frac{D_3}{(1 + K_p)^3} + \dots + \frac{D_n}{(1 + K_p)^n}$$

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1 If $D_1 = D_2 = D_3 = \dots D_n$ as is the case for preferred stock, and n approaches infinity, as is the
2 case for non-callable preferred stock without a sinking fund, then this equation reduces to:

3
$$P_0 = \frac{D_1}{K_p}$$

4 This equation can be used to solve for the annual rate of return on a preferred stock when the
5 current price and subsequent annual dividends are known. For example, with $D_1 = \$1.00$, and
6 $P_0 = \$10$, then $K_p = \$1.00 \div \$10$, or 10%.

7 The dividend discount equation, first shown, is the generic DCF valuation model for all
8 equities, both preferred and common. While preferred stock generally pays a constant
9 dividend, permitting the simplification subsequently noted, common stock dividends are not
10 constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the
11 generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \dots D_n$ are systematically
12 related to one another by a constant growth rate (g), so that $D_0(1+g) = D_1, D_1(1+g) = D_2, D_2$
13 $(1+g) = D_3$ and so on approaching infinity, and if K_s (the required rate of return on a common

$$P_0 = \frac{D_1}{K_s - g} \text{ or } P_0 = \frac{D_0(1+g)}{K_s - g}$$

14 stock) is greater than g , then the DCF equation can be reduced to:
15 which is the periodic form of the "Gordon" model.¹ Proof of the DCF equation is found in all
16 modern basic finance textbooks. This DCF equation can be easily solved as:

$$K_s = \frac{D_0(1+g)}{P_0} + g$$

¹Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams expounded the DCF model in its present form nearly two decades earlier.

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1 which is the periodic form of the Gordon Model commonly applied in estimating equity rates of
2 return in rate cases. When used for this purpose, K_s is the annual rate of return on common
3 equity demanded by investors to induce them to hold a firm's common stock. Therefore, the
4 variables D_0 , P_0 and g must be estimated in the context of the market for equities, so that the
5 rate of return, which a public utility is permitted the opportunity to earn, has meaning and
6 reflects the investor-required cost rate.

7 Application of the Gordon model with market derived variables is straightforward. For
8 example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0)
9 of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF
10 formula provides a 13.4% rate of return. The dividend yield component in this instance is
11 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual
12 rate of return required by investors. The capital gain component of the total return may be
13 calculated with two adjacent future year prices. For example, in the eleventh year of the
14 holding period, the price per share would be \$17.10 as compared with the price per share of
15 \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Dividend Yield

16
17 The historical annual dividend yield for the Gas Group is shown on Schedule 3. The
18 2007-2011 five-year average dividend yield was 3.9% for the Gas Group. The monthly
19 dividend yields for the past twelve months are shown graphically on Schedule 7. These
20 dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata
21 accumulation of the quarterly dividend amount since the last ex-dividend date.

22 The ex-dividend date usually occurs two business days before the record date of the
23 dividend (i.e., the date by which a shareholder must own the shares to be entitled to the
24 dividend payment--usually about two to three weeks prior to the actual payment). During a
25 quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend

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1 amount as the ex-dividend date approaches. The stock's price then falls by the amount of the
2 dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the
3 quarterly dividend since the time of the last ex-dividend date and to remove that amount from
4 the price. This adjustment reflects normal recurring pricing of stocks in the market, and
5 establishes a price which will reflect the true yield on a stock.

6 A six-month average dividend yield has been used to recognize the prospective
7 orientation of the ratesetting process as explained in the direct testimony. For the purpose of
8 a DCF calculation, the average dividend yields must be adjusted to reflect the prospective
9 nature of the dividend payments, i.e., the higher expected dividends for the future rather than
10 the recent dividend payment annualized. An adjustment to the dividend yield component,
11 when computed with annualized dividends, is required based upon investor expectation of
12 quarterly dividend increases.

13 The procedure to adjust the average dividend yield for the expectation of a dividend
14 increase during the initial investment period will be at a rate of one-half the growth component,
15 developed below. The DCF equation, showing the quarterly dividend payments as D_0 , may be
16 stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^2 + D_0(1+g)^3}{P_0} + g$$

17 The adjustment factor, based upon one-half the expected growth rate developed in my direct
18 testimony, will be 2.625% ($5.25\% \times .5$) for the Gas Group, which assumes that two dividend
19 payments will be at the expected higher rate during the initial investment period. Using the
20 six-month average dividend yield as a base, the prospective (forward) dividend yield would be
21 3.89% ($3.79\% \times 1.02625$) for the Gas Group.

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1 Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as
2 follows:

$$K = \frac{D_0 (1+g)^{25} + D_0 (1+g)^{50} + D_0 (1+g)^{75} + D_0 (1+g)^{1.00}}{P_0} + g$$

3 This procedure confirms the reasonableness of the forward dividend yield previously
4 calculated. The quarterly discrete adjustment provides a dividend yield of 3.91% (3.79% x
5 1.03260) for the Gas Group. The use of an adjustment is required for the periodic form of the
6 DCF in order to properly recognize that dividends grow on a discrete basis.

7 In either of the preceding DCF dividend yield adjustments, there is no recognition for
8 the compound returns attributed to the quarterly dividend payments. Investors have the
9 opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the
10 periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0} \right)^4 - 1 \right] + g$$

11 This DCF equation provides no further recognition of growth in the quarterly dividend.
12 Combining discrete quarterly dividend growth with quarterly compounding would provide the
13 following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0 (1+g)^{25}}{P_0} \right)^4 - 1 \right] + g$$

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1 A compounding of the quarterly dividend yield provides another procedure to recognize the
2 necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was
3 0.9475% ($3.79\% \div 4$) for the Gas Group. The compound dividend yield would be 3.89%
4 ($1.009597^4 - 1$) for the Gas Group, recognizing quarterly dividend payments in a forward-looking
5 manner. These dividend yields conform with investors' expectations in the context of
6 reinvestment of their cash dividend.

7 For the Gas Group, a 3.90% forward-looking dividend yield is the average ($3.89\% +$
8 $3.91\% + 3.89\% = 11.69\% \div 3$) of the adjusted dividend yield using the form $D_0/P_0 (1+.5g)$, the
9 dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend
10 yield with discrete quarterly growth.

Growth Rate

12 If viewed in its infinite form, the DCF model is represented by the discounted value of
13 an endless stream of growing dividends. It would, however, require 100 years of future
14 dividend payments so that the discounted value of those payments would equate to the
15 present price so that the discount rate and the rate of return shown by the simplified Gordon
16 form of the DCF model would be about the same. A century of dividend receipts represents
17 an unrealistic investment horizon from almost any perspective. Because stocks are not held
18 by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains
19 yield) is most relevant to investors' total return expectations. Hence, investor expected returns
20 in the equity market are provided by capital appreciation of the investment as well as receipt of
21 dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can
22 be discounted along with the annual dividend receipts during the investment holding period to
23 arrive at the investor expected return.

24 In its constant growth form, the DCF assumes that with a constant return on book
25 common equity and constant dividend payout ratio, a firm's earnings per share, dividends per

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1 share and book value per share will grow at the same constant rate, absent any external
2 financing by a firm. Because these constant growth assumptions do not actually prevail in the
3 capital markets, the capital appreciation potential of an equity investment is best measured by
4 the expected growth in earnings per share. Since the traditional form of the DCF assumes no
5 change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as
6 earnings per share. Hence, the capital gains yield is best measured by earnings per share
7 growth using company-specific variables.

8 Investors consider both historical and projected data in the context of the expected
9 growth rate for a firm. An investor can compute historical growth rates using compound
10 growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth
11 rates as provided in widely-circulated, influential publications. However, a traditional constant
12 growth DCF analysis that is limited to such inputs suffers from the assumption of no change in
13 the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as
14 earnings. Some of the factors which actually contribute to investors' expectations of earnings
15 growth and which should be considered in assessing those expectations, are: (i) the earnings
16 rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of
17 additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in
18 financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of
19 assets, and (viii) repositioning of existing assets. The realities of the equity market regarding
20 total return expectations, however, also reflect factors other than these inputs. Therefore, the
21 DCF model contains overly restrictive limitations when the growth component is stated in
22 terms of earnings per share (the basis for the capital gains yield) or dividends per share (the
23 basis for the infinite dividend discount model). In these situations, there is inadequate
24 recognition of the capital gains yields arising from stock price growth which could exceed
25 earnings or dividends growth.

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1 To assess the growth component of the DCF, analysts' projections of future growth
2 influence investor expectations as explained above. One influential publication is The Value
3 Line Investment Survey which contains estimated future projections of growth. The Value Line
4 Investment Survey provides growth estimates which are stated within a common economic
5 environment for the purpose of measuring relative growth potential. The basis for these
6 projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical
7 economic environment is represented by components and subcomponents of the National
8 Income Accounts which reflect in the aggregate assumptions concerning the unemployment
9 rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate
10 bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales,
11 earnings and dividends of a company to appropriate components or subcomponents of the
12 future National Income Accounts. These calculations provide a consistent basis for the
13 published forecasts. Value Line's evaluation of a specific company's future prospects are
14 considered in the context of specific operating characteristics that influence the published
15 projections. Of particular importance for regulated firms, Value Line considers the regulatory
16 quality, rates of return recently authorized, the historic ability of the firm to actually experience
17 the authorized rates of return, the firm's budgeted capital spending, the firm's financing
18 forecast, and the dividend payout ratio. The wide circulation of this source and frequent
19 reference to Value Line in financial circles indicate that this publication has an influence on
20 investor judgment with regard to expectations for the future.

21 There are other sources of earnings growth forecasts. One of these sources is the
22 Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus
23 earnings per share forecasts and five-year earnings growth rate estimates. The publisher of
24 IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated
25 into the First Call consensus growth forecasts. The earnings estimates are obtained from

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1 financial analysts at brokerage research departments and from institutions whose securities
2 analysts are projecting earnings for companies in the First Call universe of companies. Other
3 services that tabulate earnings forecasts and publish them are Zacks Investment Research.
4 As with the IBES/First Call forecasts, Zacks provide consensus forecasts collected from
5 analysts for most publically traded companies.

6 In each of these publications, forecasts of earnings per share for the current and
7 subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, and
8 Value Line show estimates of current-year earnings and projections for the next year. While
9 the DCF model typically focuses upon long-run estimates of growth, stock prices are clearly
10 influenced by current and near-term earnings prospects. Therefore, the near-term earnings
11 per share growth rates should also be factored into a growth rate determination.

12 Although forecasts of future performance are investor influencing², equity investors
13 may also rely upon the observations of past performance. Investors' expectations of future
14 growth rates may be determined, in part, by an analysis of historical growth rates. It is
15 apparent that any serious investor would advise himself/herself of historical performance prior
16 to taking an investment position in a firm. Earnings per share and dividends per share
17 represent the principal financial variables which influence investor growth expectations.

18 Other financial variables are sometimes considered in rate case proceedings. For
19 example, a company's internal growth rate, derived from the return rate on book common
20 equity and the related retention ratio, is sometimes considered. This growth rate measure is
21 represented by the Value Line forecast "BxR" shown on Schedule 9. Internal growth rates are
22 often used as a proxy for book value growth. Unfortunately, this measure of growth is often
23 not reflective of investor-expected growth. This is especially important when there is an

²As shown in a National Bureau of Economic Research monograph by John G. Cragg and
Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

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1 indication of a prospective change in dividend payout ratio, earned return on book common
2 equity, change in market-to-book ratios or other fundamental changes in the character of the
3 business. Nevertheless, I have also shown the historical and projected growth rates in book
4 value per share and internal growth rates.

Leverage Adjustment

6 As noted previously, the divergence of stock prices from book values creates a conflict
7 within the DCF model when the results of a market-derived cost of equity are applied to the
8 common equity account measured at book value in the ratesetting context. This is the
9 situation today where the market price of stock exceeds its book value for most companies.
10 This divergence of price and book value also creates a financial risk difference, whereby the
11 capitalization of a utility measured at its market value contains relatively less debt and more
12 equity than the capitalization measured at its book value. It is a well-accepted fact of financial
13 theory that a relatively higher proportion of equity in the capitalization has less financial risk
14 than another capital structure more heavily weighted with debt. This is the situation for the
15 Gas Group where the market value of its capitalization contains more equity than is shown by
16 the book capitalization. The following comparison demonstrates this situation where the
17 market capitalization is developed by taking the "Fair Value of Financial Instruments"
18 (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting
19 Standards ("FAS") No. 107) as shown in the annual report for these companies and the
20 market value of the common equity using the price of stock. The comparison of capital
21 structure ratios is:

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Gas Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	33.55%	43.21%
Preferred Stock	0.11	0.17
Common Equity	<u>66.34</u>	<u>56.62</u>
Total	<u>100.00%</u>	<u>100.00%</u>

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$k_u = k_e - (((k_u - i) \cdot 1-t) \cdot D / E) - (k_u - d) \cdot P / E$$

$$7.94\% = 9.15\% - (((7.94\% - 4.24\%) \cdot .65) \cdot 33.55\% / 66.34\%) - (7.94\% - 5.68\%) \cdot 0.11\% / 66.34\%$$

where k_u = cost of equity for an all-equity firm, k_e = market determined cost equity, i = cost of debt³, d = dividend rate on preferred stock⁴, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 7.94% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 7.94% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

³ The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

⁴ The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

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- 1 $k_e = k_u + (((k_u - i) 1-t) D / E) + (k_u - d) P / E$
- 2 $9.79\% = 7.94\% + (((7.94\% - 4.24\%) .65) 43.21\% / 56.62\%) + (7.94\% - 5.68\%) 0.17\% / 56.62\%.$

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INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation that is reflected in current interest rates may be quite different from the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve, which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes, which automatically provide

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1 compensation to investors for future inflation, thereby providing a lower current yield on these
2 issues.

3 Interest Rate Environment

4 Federal Reserve Board ("Fed") policy actions, which impact directly short-term interest rates
5 also substantially, affect investor sentiment in long-term fixed-income securities markets. In
6 this regard, the Fed has often pursued policies designed to build investor confidence in the
7 fixed-income securities market. Formative Fed policy has had a long history, as exemplified by
8 the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the
9 financial system, which increased the level and volatility of interest rates. The Fed has
10 indicated that it will follow a monetary policy designed to promote noninflationary economic
11 growth.

12 As background to the recent levels of interest rates, history shows that the Open
13 Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward
14 lower short-term interest rates in mid-1990 -- at the outset of the previous recession.
15 Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget
16 deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to
17 avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to
18 deal with future borrowings by the Treasury. With lower expected federal budget deficits and
19 reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury
20 bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in
21 October 1993.

22 On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate
23 (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the
24 first rise in short-term interest rates in five years. The series of seven increases doubled the
25 Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates

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1 to move up, continuing a trend, which began in the fourth quarter of 1993. The cyclical peak in
2 long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury
3 bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

4 Beginning in mid-February 1996, long-term interest rates moved upward from their
5 previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest
6 rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period
7 leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within
8 this range. After the election, interest rates moderated, returning to a level somewhat below
9 the previous trading range. Thereafter, in December 1996, interest rates returned to a range
10 of 6.5% to 7.0%, which existed for much of 1996.

11 On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-
12 quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed
13 Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by
14 persistent strength of demand in the economy, which it feared would increase the risk of
15 inflationary imbalances that could eventually interfere with the long economic expansion.

16 In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in
17 response to an increase in demand for Treasury securities caused by a flight to safety
18 triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury
19 market makes these bonds an attractive investment in times of crisis. This is because
20 Treasury securities encompass a very large market, which provides ease of trading, and carry
21 a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the
22 psychologically important 6% level for the first time since 1993.

23 Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within
24 a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of
25 1998, there was further deterioration of investor confidence in global financial markets. This

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1 loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and
2 fears associated with problems in Latin America. While not significant to the global economy
3 in the aggregate, the August 17 default by Russia had a significant negative impact on investor
4 confidence, following earlier discontent surrounding the crisis in Asia. These events
5 subsequently led to a general pull back of risk-taking as displayed by banks growing
6 reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields
7 on bonds of riskier companies. These events contributed to the failure of the hedge fund,
8 Long-Term Capital Management.

9 In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-
10 term Congressional elections. The FOMC's action was based upon concerns over how
11 increasing weakness in foreign economies would affect the U.S. economy. As recently as July
12 1998, the FOMC had been more concerned about fighting inflation than the state of the
13 economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the
14 yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-
15 term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that
16 was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets.
17 A third reduction in short-term interest rates occurred in November 1998 when the FOMC
18 reduced the Fed Funds rate to 4.75%.

19 All of these events prompted an increase in the prices for Treasury bonds, which lead
20 to the low yields described above. Another factor that contributed to the decline in yields on
21 long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to
22 market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of
23 Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and
24 lower yields. In addition, rumors of some struggling hedge funds unwinding their positions
25 further added to the gains in Treasury bond prices.

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1 The financial crisis that spread from Asia to Russia and to Latin America pushed
2 nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just
3 when supply was shrinking. There was also a move from corporate bonds to Treasury bonds
4 to take advantage of appreciation in the Treasury market. This resulted in a certain amount of
5 exuberance for Treasury bond investments that formerly was reserved for the stock market.
6 Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury
7 yields that fell from 5.10% on September 29 to 4.70% on October 5, and thereafter returned to
8 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-
9 week time frame is remarkable.

10 Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its
11 actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February
12 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%.
13 This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points
14 higher than the level that occurred at the height of the Asian currency and stock market crisis.
15 At the time, these actions were taken in response to more normally functioning financial
16 markets, tight labor markets, and a reversal of the monetary ease that was required earlier in
17 response to the global financial market turmoil.

18 As the year 2000 drew to a close, economic activity slowed and consumer confidence
19 began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC
20 reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds
21 rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary
22 policy" to eroding consumer and business confidence exemplified by weaker retail sales and
23 business spending on capital equipment and cut backs in manufacturing production.
24 Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August
25 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points

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1 decrements followed by two 25 basis points decrements. These actions took the Fed Funds
2 rate to 3.50%. The FOMC observed on August 21, 2001:

3 Household demand has been sustained, but business profits
4 and capital spending continue to weaken and growth abroad
5 is slowing, weighing on the U.S. economy. The associated
6 easing of pressures on labor and product markets is
7 expected to keep inflation contained.

8
9 Although long-term prospects for productivity growth and the
10 economy remain favorable, the Committee continues to
11 believe that against the background of its long-run goals of
12 price stability and sustainable economic growth and of the
13 information currently available, the risks are weighted mainly
14 toward conditions that may generate economic weakness in
15 the foreseeable future.

16
17 After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis
18 points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001
19 and followed the four-day closure of the financial markets following the terrorist attacks. The
20 second reduction occurred at the October 2 meeting of the FOMC where it observed:

21 The terrorist attacks have significantly heightened uncertainty
22 in an economy that was already weak. Business and
23 household spending as a consequence are being further
24 damped. Nonetheless, the long-term prospects for
25 productivity growth and the economy remain favorable and
26 should become evident once the unusual forces restraining
27 demand abate.

28
29 Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001
30 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced
31 by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate
32 by 4.75% and resulted in 1.75% for the Fed Funds rate.

33 In an attempt to deal with weakening fundamentals in the economy recovering from the
34 recession that began in March 2001, the FOMC provided a psychologically important one-half
35 percentage point reduction in the federal funds rate. The rate cut was twice as large as the

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1 market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC
2 stated that:

3 The Committee continues to believe that an accommodative
4 stance of monetary policy, coupled with still-robust
5 underlying growth in productivity, is providing important
6 ongoing support to economic activity. However, incoming
7 economic data have tended to confirm that greater
8 uncertainty, in part attributable to heightened geopolitical
9 risks, is currently inhibiting spending, production, and
10 employment. Inflation and inflation expectations remain well
11 contained.

12
13 In these circumstances, the Committee believes that today's
14 additional monetary easing should prove helpful as the
15 economy works its way through this current soft spot. With
16 this action, the Committee believes that, against the
17 background of its long-run goals of price stability and
18 sustainable economic growth and of the information currently
19 available, the risks are balanced with respect to the
20 prospects for both goals in the foreseeable future.

21
22 As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities.

23 In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second
24 quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on
25 June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on
26 June 25, 2003. In announcing its action, the FOMC stated:

27 The Committee continues to believe that an accommodative
28 stance of monetary policy, coupled with still robust underlying
29 growth in productivity, is providing important ongoing support
30 to economic activity. Recent signs point to a firming in
31 spending, markedly improved financial conditions, and labor
32 and product markets that are stabilizing. The economy,
33 nonetheless, has yet to exhibit sustainable growth. With
34 inflationary expectations subdued, the Committee judged that
35 a slightly more expansive monetary policy would add further
36 support for an economy which it expects to improve over
37 time.

38
39 Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher
40 yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's

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1 disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that
2 the Fed will not use unconventional methods for implementing monetary policy, (iii) growing
3 confidence in a strengthening economy, and (iv) concerns regarding the Federal budget
4 deficit. All these factors significantly changed the sentiment in the bond market.

5 For the remainder of 2003, the FOMC continued with its balanced monetary policy,
6 thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of
7 moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates).
8 On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14,
9 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005,
10 September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28,
11 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in
12 seventeen 25 basis point increments. These policy actions are widely interpreted as part of
13 the process of moving toward a more neutral range for the Fed Funds rate.

14 Just after the FOMC meeting on August 7, 2007, where the FOMC decided to retain a
15 5.25% Fed Funds rate, turmoil in the credit markets prompted central banks throughout the
16 world to inject over \$325 billion of reserves into the banking system over a three-day period in
17 reaction to a credit crunch. Problems had been developing earlier in 2007, beginning in the
18 market for asset-backed securities linked to subprime mortgages. Valuation uncertainties for
19 these securities caused liquidity concerns for hedge funds, investment banks, and financial
20 institutions. The market for commercial paper, the most liquid part of the credit markets for
21 non-Treasury securities, was also affected. In response to the market turmoil, the FOMC
22 issued the following statement, the first of its type since after the September 11, 2001
23 terrorists' attack.

24 The Federal Reserve is providing liquidity to facilitate the
25 orderly functioning of financial markets.
26

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1 The Federal Reserve will provide reserves as necessary
2 through open market operations to promote trading in the
3 federal funds market at rates close to the Federal Open
4 Market Committee's target rate of 5-1/4 percent. In current
5 circumstances, depository institutions may experience
6 unusual funding needs because of dislocations in money and
7 credit markets. As always, the discount window is available
8 as a source of funding.
9

10 Then, one week after its initial announcement, the FOMC made a surprise reduction of 50
11 basis points in the discount rate to narrow the spread between this rate and the target Fed
12 Funds rate. At the same time, the FOMC made the following statement:

13 Financial market conditions have deteriorated, and tighter
14 credit conditions and increased uncertainty have the potential
15 to restrain economic growth going forward. In these
16 circumstances, although recent data suggest that the
17 economy has continued to expand at a moderate pace, the
18 Federal Open Market Committee judges that the downside
19 risks to growth have increased appreciably. The Committee
20 is monitoring the situation and is prepared to act as needed
21 to mitigate the adverse effects on the economy arising from
22 the disruptions in financial markets.
23

24 Thereafter, at its regularly scheduled meeting on September 18, 2007, the FOMC reduced the
25 target Fed Funds rate to 4.75% and the discount rate was reduced to 5.25% in an effort to
26 forestall the adverse effects of the financial market turmoil on the economy generally. Further
27 reductions of 25 basis points occurred at the next two FOMC meetings on October 31, 2007
28 and on December 11, 2007. The December 11, 2007 FOMC statement indicated that:

29 Incoming information suggests that economic growth is
30 slowing, reflecting the intensification of the housing
31 correction and some softening in business and consumer
32 spending. Moreover, strains in financial markets have
33 increased in recent weeks. Today's action, combined with
34 the policy actions taken earlier, should help promote
35 moderate growth over time.
36

37 Readings on core inflation have improved modestly this year,
38 but elevated energy and commodity prices, among other
39 factors, may put upward pressure on inflation. In this
40 context, the Committee judges that some inflation risks

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1 remain, and it will continue to monitor inflation developments
2 carefully.

3
4 Recent developments, including the deterioration in financial
5 market conditions, have increased the uncertainty
6 surrounding the outlook for economic growth and inflation.
7 The Committee will continue to assess the effects of financial
8 and other developments on economic prospects and will act
9 as needed to foster price stability and sustainable economic
10 growth.

11
12 With these actions, the Fed Funds rate and the discount rate closed the calendar year 2007 at
13 4.25% and 4.75%, respectively.

14 During 2008, many critical events occurred that influenced the capital markets, and
15 hence interest rates. They include: (i) the collapse of The Bear Stearns Company and its
16 acquisition by JPMorgan Chase & Co. with the aid of the Federal Reserve Bank of New York
17 announced on March 16, 2008; (ii) the failure of IndyMac on July 11, 2008, which was at the
18 time the third-largest banking failure in U.S. history, after a "run on the bank" by depositors; (iii)
19 the placement of the government-sponsored enterprises ("GSE") Federal National Mortgage
20 Association (Fannie Mae) and Freddie Mac into conservatorship on September 7, 2008 by the
21 Federal Housing Finance Agency; (iv) the largest bankruptcy filing in history by Lehman
22 Brothers Holding, Inc. on September 15, 2008; (v) the acquisition of the banking operations of
23 Washington Mutual, then the largest U.S. savings bank, by JPMorgan Chase on September
24 24, 2008, (Washington Mutual's holding company subsequently filed for bankruptcy
25 protection); (vi) the rescue of Merrill Lynch & Co., Inc. by Bank of America on September 15,
26 2008, with assistance of the Federal government; (vii) the effective nationalization on
27 September 23, 2008, of American International Group, then the world's largest insurance
28 company, through the acquisition of 79.9% of its equity by the U.S. Treasury and (viii) other
29 significant events affecting financial markets globally. The FOMC acted decisively in response
30 to the events described above. Acting prior to its first regularly scheduled meeting in 2008, on

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1 January 22, 2008, the FOMC reduced the fed funds target by 75 basis points to 3.50% and the
2 discount rate was reduced by a corresponding amount to 4.00%. Actions by the FOMC
3 between meetings are unusual occurrences in recent years, thereby signifying the urgency
4 that the FOMC saw in taking immediate action on monetary policy in response to the financial
5 crisis. Then on January 30, 2008, the fed funds target rate and discount rate were further
6 reduced by 50 basis points, bringing those rates to 3.00% and 3.50%, respectively. Credit
7 market turmoil continued, and after the collapse of The Bear Stearn Companies noted above,
8 the FOMC stated:

9 The Federal Reserve on Sunday announced two initiatives
10 designed to bolster market liquidity and promote orderly
11 market functioning. Liquid, well-functioning markets are
12 essential for the promotion of economic growth.
13

14 First, the Federal Reserve Board voted unanimously to
15 authorize the Federal Reserve Bank of New York to create a
16 lending facility to improve the ability of primary dealers to
17 provide financing to participants in securitization markets.
18 This facility will be available for business on Monday, March
19 17. It will be in place for at least six months and may be
20 extended as conditions warrant. Credit extended to primary
21 dealers under this facility may be collateralized by a broad
22 range of investment-grade debt securities. The interest rate
23 charged on such credit will be the same as the primary credit
24 rate, or discount rate, at the Federal Reserve Bank of New
25 York.
26

27 Second, the Federal Reserve Board unanimously approved a
28 request by the Federal Reserve Bank of New York to
29 decrease the primary credit rate from 3-1/2 percent to 3-1/4
30 percent, effective immediately. This step lowers the spread of
31 the primary credit rate over the Federal Open Market
32 Committee's target federal funds rate to 1/4 percentage
33 point. The Board also approved an increase in the maximum
34 maturity of primary credit loans to 90 days from 30 days.
35

36 The Board also approved the financing arrangement
37 announced by JPMorgan Chase & Co. and The Bear Stearns
38 Companies Inc.
39

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1 Then on March 18, 2008, the FOMC reduced the fed funds rate to 2.25% and the discount rate
2 to 2.50%. Afterward on April 30, 2008, the FOMC further reduces the fed funds rate to 2.00%
3 and the discount rate to 2.25%. At subsequent meetings the FOMC held the fed funds rate
4 steady. Then on October 8, 2008, the FOMC took another unusual unscheduled action by
5 reducing the Fed Funds rate to 1.50% and the discount rate to 1.75%. Then, on October 29,
6 the FOMC lowered the Fed Funds rate to 1.00% and the discount rate to 1.25%. As 2008
7 ended, the FOMC lowered the Fed Funds rate to a target range of 0.00% to 0.25%, its lowest
8 rate ever. As a further response to the financial crisis, Congress passed and the President
9 signed on October 3, 2008, the Emergency Economic Stabilization Act of 2008, which, among
10 other provisions, provides the mechanism to deploy up to \$700 billion through the Troubled
11 Asset Relief Program ("TARP") to address urgent needs created by the credit crisis the
12 country has experienced. Then, the Federal Reserve Board instituted its Commercial Paper
13 Funding Facility ("CPFF"), which was authorized on October 7, 2008, and it participated in
14 coordinated efforts by major central banks to support financial stability and to maintain flows of
15 credit in the banking system. These programs included a \$75 billion Term Auction Facility
16 ("TAF"), a future TAF auction totaling \$150 billion, and an increase to \$620 billion of swap
17 authorizations with central banks in Canada, England, Japan, Denmark, the European Union,
18 Norway, Australia, Sweden, and Switzerland. Further, on February 17, 2009, the President
19 signed the American Recovery and Reinvestment Act that committed \$789 billion by the
20 Federal government in an effort to create jobs, jumpstart growth and to transform the economy
21 in reaction to the recession that began in December 2007.

22 The FOMC maintained its target range of 0.00% to 0.25% throughout the remainder of
23 2009, for 2010, 2011, and 2012 to date. At its August 1, 2012 meeting, the FOMC stated:

24 Information received since the Federal Open Market
25 Committee met in June suggests that economic activity
26 decelerated somewhat over the first half of this year.

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1 Growth in employment has been slow in recent months,
2 and the unemployment rate remains elevated. Business
3 fixed investment has continued to advance. Household
4 spending has been rising at a somewhat slower pace than
5 earlier in the year. Despite some further signs of
6 improvement, the housing sector remains depressed.
7 Inflation has declined since earlier this year, mainly
8 reflecting lower prices of crude oil and gasoline, and
9 longer-term inflation expectations have remained stable.

10
11 Consistent with its statutory mandate, the Committee
12 seeks to foster maximum employment and price stability.
13 The Committee expects economic growth to remain
14 moderate over coming quarters and then to pick up very
15 gradually. Consequently, the Committee anticipates that
16 the unemployment rate will decline only slowly toward
17 levels that it judges to be consistent with its dual mandate.
18 Furthermore, strains in global financial markets continue to
19 pose significant downside risks to the economic outlook.
20 The Committee anticipates that inflation over the medium
21 term will run at or below the rate that it judges most
22 consistent with its dual mandate.

23
24 To support a stronger economic recovery and to help
25 ensure that inflation, over time, is at the rate most
26 consistent with its dual mandate, the Committee expects to
27 maintain a highly accommodative stance for monetary
28 policy. In particular, the Committee decided today to keep
29 the target range for the federal funds rate at 0 to 1/4
30 percent and currently anticipates that economic conditions--
31 including low rates of resource utilization and a subdued
32 outlook for inflation over the medium run--are likely to
33 warrant exceptionally low levels for the federal funds rate
34 at least through late 2014.

35
36 The Committee also decided to continue through the end
37 of the year its program to extend the average maturity of its
38 holdings of securities as announced in June, and it is
39 maintaining its existing policy of reinvesting principal
40 payments from its holdings of agency debt and agency
41 mortgage-backed securities in agency mortgage-backed
42 securities. The Committee will closely monitor incoming
43 information on economic and financial developments and
44 will provide additional accommodation as needed to
45 promote a stronger economic recovery and sustained
46 improvement in labor market conditions in a context of
47 price stability.
48

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Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim, which lenders have on the earnings, and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 10 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds, which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 10. There, it is shown that those spreads were about one percent during the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant

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1 widening of spreads in 1998 was unexpected by some technically savvy investors, as shown
2 by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its
3 debt on August 17, some investors had to cover short positions when Treasury prices spiked
4 upward. Short covering by investors that guessed wrong on the relationship between
5 corporate and Treasury bonds also contributed to the run-up in Treasury bond prices by
6 increasing the demand for them. This helped to contribute to a widening of the spreads
7 between corporate and Treasury bonds.

8 As shown on page 3 of Schedule 10, the spread in yields between A-rated public utility
9 bonds and 20-year Treasury bonds was about one percentage point prior to 1998, 1.32% in
10 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in
11 2004, 1.01% in 2005, 1.08% in 2006, 1.16% in 2007, 2.17% in 2008, 1.93% in 2009, 1.43% in
12 2010, and 1.42% in 2011. As shown by the monthly data presented on pages 4 and 5 of
13 Schedule 10, the interest rate spread between the yields on 20-year Treasury bonds and A-
14 rated public utility bonds was 1.62 percentage points for the twelve-months ended July 2012.
15 For the six- and three-month periods ending July 2012, the yield spread was 1.65% and
16 1.72%, respectively.

17 Beginning in August 2007, spreads widened significantly with the development of the
18 credit crisis. As the credit crisis developed, there was a flight to quality, thereby increasing
19 demand and reducing the yields on Treasury obligations. While this situation is most
20 pronounced at the shortest end of the yield curve (i.e., obligations with the shortest duration),
21 all Treasury yields display relatively low yields by reference to other credit obligations. By the
22 end of 2009, the spread in yields on A-rated public utility bonds and 20-year Treasury bonds
23 declined significantly from the peak of the credit crisis.

Risk-Free Rate of Return in the CAPM

24
25 Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 12

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1 provides the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners
2 of the CAPM would advocate the use of short-term treasury yields (and some would argue for
3 the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of
4 longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has
5 indicated:

6 The Cost of Capital in a Regulatory Environment. When
7 discounting cash flows projected over a long period, it is
8 necessary to discount them by a long-term cost of capital.
9 Additionally, regulatory processes for setting rates often
10 specify or suggest that the desired rate of return for a
11 regulated firm is that which would allow the firm to attract and
12 retain debt and equity capital over the long term. Thus, the
13 long-term cost of capital is typically the appropriate cost of
14 capital to use in regulated ratesetting. (Stocks, Bonds, Bills
15 and Inflation - 1992 Yearbook, pages 118-119)
16

17 As indicated above, long-term Treasury bond yields represent the correct measure of the risk-
18 free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be
19 avoided for several reasons. First, rates should be set on the basis of financial conditions that
20 will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields
21 are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy,
22 political, and economic situations. Moreover, Treasury bill yields have been shown to be
23 empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-
24 free rate of return in the CAPM should be derived from quality long-term corporate bonds. To
25 take a balanced approach to the risk-free rate of return, the yield on long-term Treasury bonds
26 has been used for this purpose.

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors, which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

1 The Risk Premium approach recognizes the required compensation for the more risky
2 common equity over the less risky secured debt position of a lender. The cost of equity stated
3 in terms of the familiar risk premium approach is:

$$k=i+RP$$

4
5 where, the cost of equity (" k ") is equal to the interest rate on long-term corporate debt (" i "),
6 plus an equity risk premium (" RP ") which represents the additional compensation for the riskier
7 common equity.

8 Equity Risk Premium

9 The equity risk premium is determined as the difference in the rate of return on debt
10 capital and the rate of return on common equity. Because the common equity holder has only
11 a residual claim on earnings and assets, there is no assurance that achieved returns on
12 common equities will equal expected returns. This is quite different from returns on bonds,
13 where the investor realizes the expected return during the entire holding period, absent
14 default. It is for this reason that common equities are always more risky than senior debt
15 securities. There are investment strategies available to bond portfolio managers that
16 immunize bond returns against fluctuations in interest rates because bonds are redeemed
17 through sinking funds or at maturity, whereas no such redemption is mandated for public utility
18 common equities.

19 It is well recognized that the expected return on more risky investments will exceed the
20 required yield on less risky investments. Neither the possibility of default on a bond nor the
21 maturity risk detracts from the risk analysis, because the common equity risk rate differential
22 (i.e., the investor-required risk premium) is always greater than the return components on a
23 bond. It should also be noted that the investment horizon is typically long-run for both
24 corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

1 to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or
2 starting point with which to track and measure the cost rate of common equity capital. There is
3 no need to segment the bond yield according to its components, because it is the total return
4 demanded by investors that is important for determining the risk rate differential for common
5 equity. This is because the complete bond yield provides the basis to determine the
6 differential, and as such, consistency requires that the computed differential must be applied to
7 the complete bond yield when applying the risk premium approach. To apply the risk rate
8 differential to a partial bond yield would result in a misspecification of the cost of equity
9 because the computed differential was initially determined by reference to the entire bond
10 return.

11 The risk rate differential between the cost of equity and the yield on long-term
12 corporate bonds can be determined by reference to a comparison of holding period returns
13 (here defined as one year) computed over long time spans. This analysis assumes that over
14 long periods of time investors' expectations are on average consistent with rates of return
15 actually achieved. Accordingly, historical holding period returns must not be analyzed over an
16 unduly short period because near-term realized results may not have fulfilled investors'
17 expectations. Moreover, specific past period results may not be representative of investment
18 fundamentals expected for the future. This is especially apparent when the holding period
19 returns include negative returns, which are not representative of either investor requirements
20 of the past or investor expectations for the future. The short-run phenomenon of unexpected
21 returns (either positive or negative) demonstrates that an unduly short historical period would
22 not adequately support a risk premium analysis. It is important to distinguish between
23 investors' motivation to invest, which encompass positive return expectations, and the
24 knowledge that losses can occur. No rational investor would forego payment for the use of

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 11 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return, which divides the entire series of annual returns in half, and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. While the use of the geometric mean would be inappropriate for CAPM purposes due to the specification of that model, it can provide a limit of the bounds for the Risk Premium approach that does not contain the single-period limitation.

This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2007, the risk premiums for each class of equity are:

	<u>S&P Composite</u>	<u>S&P Public Utilities</u>
Arithmetic Mean	<u>5.82%</u>	<u>5.52%</u>
Geometric Mean	4.23%	3.47%
Median	<u>9.27%</u>	<u>7.50%</u>
Midpoint of Range	<u>6.75%</u>	<u>5.49%</u>
Average of Arithmetic Mean and Midpoint of Range	<u>6.29%</u>	<u>5.51%</u>

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

APPENDIX G TO DIRECT TESTIMONY OF PAUL R. MOUL

1 If, however, specific historical periods were also analyzed in order to match more
2 closely historical fundamentals with current expectations, the results provided on page 2 of
3 Schedule 11 should also be considered. One of these sub-periods included the 56-year
4 period, 1952-2007. These years follow the historic 1951 Treasury-Federal Reserve Accord,
5 which affected monetary policy and the market for government securities.

6 A further investigation was undertaken to determine whether realignment has taken
7 place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the
8 financial markets. In each case, the public utility risk premiums were computed by using the
9 arithmetic mean, and the geometric means and medians to establish the range shown by
10 those values. The time periods covering the more recent periods 1974 through 2007 and
11 1979 through 2007 contain events subsequent to the initial oil shock and the advent of
12 monetarism as Fed policy, respectively. For the 56-year, 34-year and 29-year periods, the
13 public utility risk premiums were 6.58%, 6.08%, and 6.37% respectively, as shown by the
14 average of the specific point-estimates and the midpoint of the ranges provided on page 2 of
15 Schedule 11.

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium, which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line, which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 To apply the traditional CAPM theory, three inputs are required: the beta coefficient
2 (" β "), a risk-free rate of return (" R_f "), and a market premium (" $R_m - R_f$ "). The cost of equity
3 stated in terms of the CAPM is:

$$k = R_f + \beta (R_m - R_f)$$

4
5 As previously indicated, it is important to recognize that the academic research has
6 shown that the security market line was flatter than that predicted by the CAPM theory and it
7 had a higher intercept than the risk-free rate. These tests indicated that for portfolios with
8 betas less than 1.0, the traditional CAPM would understate the return for such stocks.
9 Likewise, for portfolios with betas above 1.0, these companies had lower returns than
10 indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio
11 diversification investors will minimize the effect of the unsystematic (diversifiable) component
12 of investment risk. Therefore, the CAPM must also be used with other models of the cost of
13 equity, especially when it is not known whether the average public utility investor holds a well-
14 diversified portfolio.

Beta

15
16 The beta coefficient is a statistical measure, which attempts to identify the non-
17 diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of
18 return on a particular security with general market movements. Under the CAPM theory, a
19 security that has a beta of 1.0 should theoretically provide a rate of return equal to the return
20 rate provided by the market. When employing stock price changes in the derivation of beta, a
21 stock with a beta of 1.0 should exhibit a movement in price, which would track the movements
22 in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a
23 one percent increase in the return on the market will result, on average, in a one percent
24 increase in the return on the particular investment. An investment, which has a beta less than
25 1.0, is considered to be less risky than the market.

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 The beta coefficient (" β "), the one input in the CAPM application, which specifically
2 applies to an individual firm, is derived from a statistical application, which regresses the
3 returns on an individual security (dependent variable) with the returns on the market as a
4 whole (independent variable). The beta coefficients for utility companies typically describe a
5 small proportion of the total investment risk because the coefficients of determination (R^2) are
6 low.

7 Page 1 of Schedule 12 provides the betas published by Value Line. By way of
8 explanation, the Value Line beta coefficient is derived from a "straight regression" based upon
9 the percentage change in the weekly price of common stock and the percentage change
10 weekly of the New York Stock Exchange Composite average using a five-year period. The
11 raw historical beta is adjusted by Value Line for the measurement effect resulting in
12 overestimates in high beta stocks and underestimates in low beta stocks. Value Line then
13 rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the
14 computation of its betas.

Market Premium

15
16 The final element necessary to apply the CAPM is the market premium. The market
17 premium by definition is the rate of return on the total market less the risk-free rate of return
18 (" $R_m - R_f$ "). In this regard, the market premium in the CAPM has been calculated from the total
19 return on the market of equities using forecast and historical data. The future market return is
20 established with forecasts by Value Line using estimated dividend yields and capital
21 appreciation potential.

22 With regard to the forecast data, I have relied upon the Value Line forecasts of capital
23 appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to
24 the July 27, 2012 edition of The Value Line Investment Survey Summary and Index, (see page
25 5 of Schedule 12) the total return on the universe of Value Line equities is:

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

			Median		Median
		Dividend	Appreciation		Total
		Yield	Potential		Return
1	As of July 27, 2011	2.4%	+ 15.02%	⁽¹⁾	= 17.42%

2 The tabulation shown above provides the dividend yield and capital gains yield of the
3 companies followed by Value Line. Another measure of the total market return is provided by
4 the DCF return on the S&P 500 Composite index. That return is shown below.

DCF Result for the S&P 500 Composite					
D/P	(	1+.5g	)	+	g = k
2.16%	(	1.0521	)	+	10.42% = 12.69%

5 where: Price (P) at 31-Jul-2012 = 1379.32
Dividend (D) for 2nd Qtr. '12 = 7.45
Dividend (D) annualized = 29.80
Growth (g) First Call EpS = 10.42%

6 Using these indicators, the total market return is 15.06% ($17.42\% + 12.69\% = 30.11\% \div 2$)
7 using both the Value Line and S&P derived returns. With the 15.06% forecast market return
8 and the 3.25% risk-free rate of return, an 11.81% ($15.06\% - 3.25\%$) market premium would be
9 indicated using forecast market data.

10 I have also provided market premiums that have been widely circulated among the
11 investment and academic community, which today is published by Morningstar, Inc. These
12 data are contained in the 2012 Ibbotson® Stocks, Bonds, Bills and Inflation ("SBBI") Classic
13 Yearbook. From the data provided on page 6 of Schedule 12, I calculate a market premium
14 using the historical common stock arithmetic mean returns of 11.8% less government bond
15 arithmetic mean returns of 6.1%. For the period 1926-2011, the market premium was 5.7%
16 ($11.8\% - 6.1\%$). I should note that the arithmetic mean must be used in the CAPM because it

¹The estimated median appreciation potential is forecast to be 75% for 3 to 5 years hence.
The annual capital gains yield at the midpoint of the forecast period is 15.02% (i.e., $1.75^{25} - 1$).

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

1 is a single period model. It is further confirmed by Ibbotson who has indicated:

2 *Arithmetic Versus Geometric Differences*

3 For use as the expected equity risk premium in the CAPM, the
4 *arithmetic* or *simple difference* of the *arithmetic* means of stock
5 market returns and riskless rates is the relevant number. This
6 is because the CAPM is an additive model where the cost of
7 capital is the sum of its parts. Therefore, the CAPM expected
8 equity risk premium must be derived by arithmetic, *not*
9 *geometric*, subtraction.

10 *Arithmetic Versus Geometric Means*

11 The expected equity risk premium should always be calculated
12 using the arithmetic mean. The arithmetic mean is the rate of
13 return which, when compounded over multiple periods, gives
14 the mean of the probability distribution of ending wealth
15 values. This makes the arithmetic mean return appropriate for
16 computing the cost of capital. The discount rate that equates
17 expected (mean) future values with the present value of an
18 investment is that investment's cost of capital. The logic of
19 using the discount rate as the cost of capital is reinforced by
20 noting that investors will discount their (mean) ending wealth
21 values from an investment back to the present using the
22 arithmetic mean, for the reason given above. They will
23 therefore require such an expected (mean) return
24 prospectively (that is, in the present looking toward the future)
25 to commit their capital to the investment. (Stocks, Bonds, Bills
26 and Inflation - 1996 Yearbook, pages 153-154)
27
28

29 Also shown on page 6 of Schedule 12 is the long-horizon expected market premiums
30 of 6.62% also published in the SBBI Classic Yearbook. An average of the historical and
31 expected SBBI market premium is 6.16% ($5.7\% + 6.62\% = 12.32\% \div 2$).

32 For the CAPM, a market premium of 8.99% ($6.16\% + 11.81\% = 17.97\% \div 2$) would be
33 reasonable which is the average of the 6.16% SBBI data and the 11.81% Value Line and S&P
34 500 data.

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Panpilas W. Fischer, being Manager of Income Taxes at NiSource Corporate Services Company ("NCSC"), hereby state that the testimony set forth in Columbia Statement Nos. 11 and 111-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. PWF-1R and PWF-R2, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Panpilas W. Fischer

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

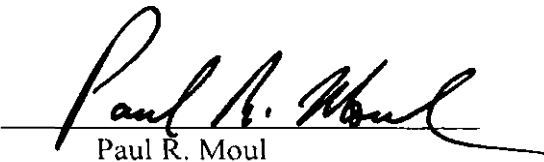
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Paul R. Moul, being managing Consultant with P. Moul & Associates, hereby state that the testimony set forth in Columbia Statement Nos. 10 and 110-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Appendix A through I, Exhibit 400R and Schedules 1 through 4, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Paul R. Moul

2-13-13

Hbg 8

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No.R-2012-2321748

DIRECT TESTIMONY OF

PANPILAS W. FISCHER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

JUNE 6, 2012

1 Q. Please state your name and business address.

2 A. My name is Panpilas W. Fischer. My business address is 200 Civic Center Drive,
3 Columbus, Ohio 43215.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by NiSource Corporate Services Company ("NCSC"), a management
6 and services subsidiary of NiSource Inc. ("NiSource"). My current title is Manager
7 of Income Taxes at NCSC.

8 Q. Please briefly describe your professional experience.

9 A. I began my career with KPMG as a staff auditor in 1987. I then joined the firm of
10 Clark, Schaefer, Hackett and Co., CPAs as a Senior Auditor in 1989 where I
11 performed financial audits, reviews and compilations, and prepared and reviewed
12 tax returns. In October 2000, I started working as a tax analyst for NCSC and in
13 October 2003 I was promoted to my current position.

14 Q. Please describe your educational background.

15 A. I received Bachelor of Business Administration in Accounting in 1987 from the
16 Ohio State University. I am a Certified Public Accountant and member of the Ohio
17 Society of Certified Public Accountants.

18 Q. What are your responsibilities in your current position?

19 A. In my current position with NCSC, my principal responsibilities include
20 supervision and preparation of all of Columbia Gas of Pennsylvania's ("Columbia"
21 or "the Company") income tax activities including the booking of income tax
22 accruals and deferred tax entries, the filing of income tax returns, tax research and
3 planning and the preparation of income tax data and related testimony for rate

proceedings.

Q. Have you previously testified before this or any other regulatory agency?

A. I have previously provided written testimony to the Kentucky Public Service Commission, the Public Utilities Commission of Ohio and the Maryland Public Service Commission.

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

A. The primary purpose of my testimony is to present and support Columbia's income tax and other tax expense included in the cost of service. The filing includes federal and state income tax recovery, reduction of rate base for deferred income taxes, as well as a reduction to tax expense resulting from the Company's 2008 change in tax method of accounting for repairs. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve month period ending May 31, 2012) and Exhibit 107 for the Fully Forecasted Rate Year (the twelve-month period ending June 30, 2014). Taxes other than income are included in Exhibit 6 and Exhibit 106.

Q. Will you explain the basis for the income tax calculations for the Historic Test Year?

A. The tax calculations were made in accordance with federal and state laws. The federal tax rate is 35% and the Pennsylvania tax rate is 9.99%. The Historic Test Year tax calculations have been impacted by certain items that have been historically treated as flow-through or deferred in rate making proceedings.

Q. Can you explain the flow-through items included in the tax provision?

A. Prior to 1981, federal tax statutes did not require full normalization of accelerated

1 tax depreciation versus book straight line depreciation recovered in rates.
2 Beginning in 1981 for Columbia, normalization, under the Internal Revenue Code,
3 does not permit the flow-through or refund of accelerated depreciation benefits by
4 a utility to its customers. Such benefits must be provided for in a deferred tax
5 reserve, and that reserve may be allowed as a rate base reduction. Prior to 1984,
6 the Company flowed-through the benefits of accelerated depreciation for vintage
7 years prior to 1981. Beginning in 1984, the Company began to normalize the
8 remaining book versus tax differences on Asset Depreciation Range vintages (1971
9 through 1980) based upon the Commission's order in Docket No. R-832493. For
10 the Historic Test Year, we are in a position where the Company has very little in
11 terms of tax depreciation remaining on pre-1981 assets. Thus, we are in a
12 turnaround position, since book depreciation is now higher than tax depreciation.
13 In addition, the Company has excess deferred taxes that were originally computed
14 at a 46% federal tax rate for 1981-1987 vintages that are being refunded in rates
15 under the Average Rate Assumption Method ("ARAM"). This method required the
16 Company to keep deferred taxes intact until book depreciation exceeds tax
17 depreciation for those vintage years, and to flow back the deferred tax excess
18 between the 46% rate and the current 35%. Since most of the property was 15 year
19 property for federal purposes, the excess is in a turnaround situation. During the
20 Historic Test Year, the company recorded a lower tax expense by \$309,311 in its
21 federal tax provision related to the excess deferred taxes. It projects the number to
22 be \$628,368 for the Fully Forecasted Rate Year.

3 Q. How is Columbia handling the reduction in tax caused by the 2008 change in

1 method of accounting for repairs?

2 A. As agreed in the settlement of Columbia's 2010 rate case (Docket No. R-2009-
3 2149262), a refund of the \$37,487,634 is being made to customers, which reflects
4 the cash benefit received in 2009 for the tax year 2008 method change. As of
5 November 1, 2011, a total of \$4,451,393 was amortized and an additional
6 \$24,857,392 is being amortized through the period ended June 30, 2013.
7 Beginning July 1, 2013 (the approximate effective date of rates after a full
8 suspension period), this case reflects the remaining \$8,178,846 being amortized
9 over a period of 24 months. As provided in the 2010 Rate Case settlement, the
10 amortization is without interest and without a deduction of the unamortized
11 balance from rate base.

12 Q. How does the change in method impact Columbia's taxable income going forward?

13 A. For a period of time, the repairs deduction is anticipated to exceed deductions if
14 the plant had been capitalized for tax purposes, and thus will continue to result in a
15 reduction to taxable income. However, beginning post October 18, 2011 (the
16 effective date of Columbia's most recent rate case) the repairs deduction is being
17 normalized under deferred tax accounting, so there will be no impact on total
18 federal tax expense.

19 Q. Are there any other items treated as flow-through in the rate-making process?

20 A. Yes. The Company continues to reduce its income tax allowance for the net cost of
21 retirements, which is allowed as a deduction on its tax return. In addition, there
22 are four permanent differences included in the tax provision. Permanent
differences are items of income or expense that will never be included in the federal

1 tax return. Currently, the federal government subsidizes a portion of the
2 Company's benefit costs on prescription drugs, and the subsidy is not included in
3 taxable income. This benefit is included in the tax provision. Items increasing tax
4 expense as a result of being non-deductible include expenses for business meals,
5 employee stock purchase plan compensation and lease expense on vehicles.

6 Q. How has the Company handled Pennsylvania Corporate Net Income Taxes in its
7 calculation of deferred income taxes for depreciation?

8 A. The Company, based on prior Commission orders, has not normalized deferred
9 state income taxes. The company continues to flow-through the state income tax
10 benefits of accelerated depreciation on its book depreciable assets.

11 Q. Did the Company receive a refund from Pennsylvania for the change in method?

12 A. No. The Company had a \$149.2 million net operating loss for 2008 that it carried
13 forward into 2009 and will carry forward into future years. The Company reduced
14 its Pennsylvania taxable income by 15% of taxable income in 2009. The Company
15 also had a \$4.1 million net operating loss for 2010 that is being carried forward.
16 The reduction is the higher of \$3,000,000 or 20% in 2010 and thereafter. The
17 Company's claimed tax expense takes such benefit into account.

18 Q. Was a Consolidated Tax Adjustment included in the claim in this case?

19 A. Similar to the Company's 2010 base rate case, a Consolidated Tax Adjustment was
20 not included in this case because Columbia Gas of Pennsylvania was a loss
21 company on average for the three year period. The loss is the result of the actions
22 by the Company that generated the tax refund I explained previously, as well as 50-
3 100% bonus depreciation allowed under federal tax law (the Tax Relief,

Unemployment Insurance Reauthorization, and Job Creation Act of 2010) for most assets placed in service during the Historic Test Year. Under these circumstances, it is appropriate not to apply a consolidated income tax adjustment in this case. Nevertheless, I have provided details of the income and losses of affiliated companies for the three year period in Exhibit No. 7 pages 2 through 4.

Q. Are there other reasons why a consolidated tax adjustment is not appropriate?

A. Yes, most of the "tax loss" generated by the NiSource system is the result of tax deductions generated by debt issued to finance the acquisition of Columbia Energy Group. As shown on Exhibit No. 7 pages 3 and 4, over \$205 million of the \$290 million of average annual losses for unregulated companies arise from this debt which is recorded as a loss for NiSource Inc. The cost of this debt is not reflected in Columbia's rates and the debt does not finance rate base. Since the debt cost associated with those incremental investments outside of the rate base is not reflected in Columbia's rates to customers, it is not appropriate to provide the tax deductions associated with such cost to ratepayers.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, page 19 of Exhibit 7 delineates total pro forma tax expense of \$5,176,268. This total includes a credit of (\$539,603) of state income taxes, which is based on \$64,646,387 of operating income less \$21,048,713 of interest expense on debt for total pre-tax income of \$43,497,674, resulting in an effective state income tax rate of 0%. This reduced expense, as compared to the Pennsylvania statutory rate of 9.99%, is a result of the flow through treatment of

1 accelerated depreciation deductions for state income tax purposes. The expense for
2 federal income taxes is \$5,715,871, or 13.1%, of the pre-tax income less state
3 income taxes. This 13.1% expense is 21.9% less than the federal statutory rate of
4 35%. The difference is largely attributable to the tax repairs deduction being
5 flowed through in rates.

6 Q. Please continue with respect to the Forecasted Future Test Year.

7 A. For the proposed income tax recovery, the amounts can be found on Exhibit 107
8 pages 16 and 17. The same individual items creating a variance from statutory
9 rates in the historical data create a variance in proposed rates. Minor adjustments
10 have been made to reflect forecasted numbers during the forecast test year.

11 Q. And how have taxes impacted the Company's rate base?

12 A. Exhibit 107 page 5 delineates the reduction in rate base for deferred income taxes.
13 The amounts include deferred taxes on net utility plant that have or will be
14 normalized by the end of the Fully Forecasted Rate Year, as well as deferred taxes
15 on inventory, customer advances and building lease.

16 Q. Are there any new adjustment impacting deferred taxes in rate base?

17 A. Included in deferred income taxes is an adjustment for Section 263a mixed service
18 costs. Mixed service costs ("MSC") are general and administrative costs that are
19 indirectly allocable (i.e. not exclusively attributable) to activities related to self-
20 constructed assets and inventory property and must be partially capitalized rather
21 than fully deducted for book and tax purposes. The allocation methods differ for
22 book and tax purposes. The adjustment can be found on Exhibit 107 page 9, line
3 20. Internal Revenue Service Industry Director's Directive (IDD) 5 issued

1 September 15, 2009 provides guidelines on the method transmission and
2 distributions companies can use to allocate MSC for tax purposes using the
3 reasonable allocation method. The Company is proposing to normalize these
4 deductions for federal income taxes which result in a different book vs. tax basis on
5 self-constructed assets. This is similar treatment to the book vs. tax difference for
6 the repairs deduction which was specifically allowed normalization treatment in
7 Columbia's 2010 rate case and capitalized interest which is also normalized for
8 federal income taxes and results in an increase to deferred income taxes which will
9 turn around through decreased tax depreciation deductions over the life of the
10 asset.

11 Q. Please explain the inclusion of deferred taxes for the Federal Net Operating Loss in
12 rate base on Exhibit 107, Page 5.

13 A. As a result of taking deductions for 50-100% bonus depreciation, Columbia has
14 experienced net taxable losses for the years 2008 and 2010. The result is that
15 Columbia booked deferral taxes in those years for which the Company has not
16 received any cash. The Company cannot reflect an increase in deferred taxes for tax
17 depreciation deductions that have not been realized. To do so would violate the
18 principles of the Normalization requirements under the Internal Revenue Code.
19 Past IRS rulings addressing this issue have made it clear that companies cannot
20 reduce rate base for benefits that have not been realized. Therefore, included as an
21 increase to rate base is a deferred tax asset in the amount of \$3,309,190 which
22 represents the remaining balance of un-utilized net operating loss.

23 Q. Why have you included an adjustment to deferred taxes for the fully forecasted rate

1 year on Exhibit 107, Page 5?

2 A. Whenever there are estimated changes in the deferred taxes that occur in a future
3 rate period, the Normalization requirements of the Internal Revenue Code require
4 that the deferred taxes be reflected on a pro rata basis as provided under Reg.
5 Section 1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test
6 period after the effective date of the rate order. Under the pro rata basis, the
7 change in the deferred taxes is determined by multiplying the change by a fraction
8 of the number of days remaining in the period at the time such change is to be
9 accrued over the total number of days in the future period. Applying this
10 calculation resulted in a decrease to deferred taxes of \$11,993,511.

11 Q. Are you sponsoring any other expense adjustments?

12 A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act
13 ("FICA"), Property Tax and Capital Stock Tax. These adjustments are delineated
14 on Exhibits 6 and 106.

15 Q. Please explain the FICA adjustment.

16 A. The adjustment represents an increase in FICA taxes as they apply to the payroll
17 adjustments discussed in Company witness Gore's testimony (Columbia Statement
18 No. 4). An increase in payroll taxes of \$208,216 is reflected in the annualized
19 Historic Test Year. Please see Exhibit No. 6, Schedule 2, Page 3 of 5 for the
20 calculation. For the Fully Forecasted Rate Year, the Company is projecting a
21 higher payroll base, thus increasing payroll taxes by \$49,067. Please see Exhibit
22 No. 106, Schedule 2, Page 3 of 5 for the calculation.

Q. Please explain the property tax adjustment.

1 A. The PURTA tax and the locally assessed property tax on Pennsylvania property are
2 both consistent with the most recent year end tax levels as of December 31, 2010.
3 The West Virginia tax for gas stored underground was developed using the
4 December 31, 2011 assessed value and the 2011 tax rate. This annualized level of
5 \$642,142 is higher than the Historic Test Year level of \$487,532, as shown on
6 Exhibit 6, Schedule 2, Page 4 of 5, resulting in an upward adjustment of \$154,610
7 due to the increase in the assessed value on the gas stored underground in West
8 Virginia. The detail supporting this calculation for the Fully Forecasted Rate Year
9 is provided on Exhibit 106, Schedule 2, Page 4. The pro-forma Fully Forecasted
10 Rate Year was not adjusted from this level.

11 Q. Please explain the Capital Stock tax adjustment.

12 A. Similar to the property tax adjustment, the capital stock tax adjustment begins
13 with the last known basis of December 31, 2010. To this, the 2012 rate was applied,
14 resulting in a (\$295,894) downward adjustment from the Historic Test Year level.
15 The major reason for the adjustment downward is the rate decrease due to the
16 phase out of the Pennsylvania capital stock tax. Since the capital stock tax is
17 calculated on a basis as of the end of a calendar year period, using a rate of .00089
18 which is in effect for 2013, the capital stock tax for the first six months of the fully
19 forecasted rate year ending June 30, 2014 would actually result in a capital stock
20 tax of \$128,184. However since the capital stock tax will not recur in 2014 due to
21 the phase out by the end of the Fully Forecasted Rate Year, a zero capital stock tax
22 expense is reflected using the last known basis of December 31, 2010 and applying
a zero rate for the Fully Forecasted Rate Year.

1 Q. Please explain the License and Franchise Tax adjustment.

2 A. The License and Franchise tax annualized level of \$6,251 is the same as the
3 Historic Test Year level. This adjustment is to reflect the latest West Virginia
4 franchise tax liability for the Company. The pro-forma Fully Forecasted Rate Year
5 was not adjusted from this level.

6 Q. Please explain the Other Tax adjustment on Exhibit 106 Schedule 2 Page 2.

7 A. The annualized level of \$32,056 was not adjusted for the Historic Test Year.
8 However, the pro-forma Fully Forecasted Rate Year was reduced to remove Ohio
9 Commercial Activity Tax on off-system sales that are not foreseen to recur in the
10 Fully Forecasted Rate Year.

11 Q. Does this conclude your testimony?

2 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

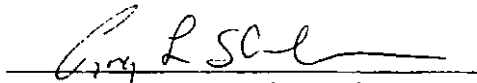
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Gregory L. Shoemaker, being Lead Financial Analyst of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 112-R is true and correct to the best of my knowledge, information and belief. I am assuming responsibility for and am sponsoring Columbia Statement No. 12, the direct testimony of Summer D. Cogar, which I assisted in preparing. If asked orally at a hearing in this matter, my answers would be as set forth in the identified pieces of testimony. I further state that I am responsible for Exhibit No. GLS-1R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Gregory L. Shoemaker

2-13-13

Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
SUMMER D. COGAR
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

SEPTEMBER 28, 2012

1 Q: Please state your name and business address.

2 A: My name is Summer D. Cogar. My business address is 200 Civic Center Drive,
3 Columbus, Ohio 43215.

4 Q: By whom are you employed and in what capacity?

5 A: I am employed by NiSource Corporate Services Company ("NCSC"). My current
6 title is Special Studies Accounting Manager of NiSource Corporate Services
7 Company.

8 Q: Please briefly describe your professional experience.

9 A: I was employed by Schneider Downs & Company, Inc. from August 2004 to Au-
10 gust 2007. At this CPA firm, I started as a Staff Auditor and was then promoted
11 to In-charge Auditor with in the Assurance Services Group. In August 2007, I
12 was hired by Limited Brands, Inc. as a Senior Financial Analyst of the Limited
13 Services Company Accounting and Financial Reporting team within Corporate
14 Finance where I was employed until August 2009. In August 2009, I accepted a
15 position as the Corporate Accounting Manager at inVentiv Communications
16 where I was employed until March 2010. In March 2010, I accepted a position as
17 the Corporate Accounting Manager within NCSC and then Manager of Special
18 Studies of NCSC in October 2011.

19 Q: What are your responsibilities as Accounting Manager?

20 A: As Special Studies Accounting Manager of NCSC, my principal responsibilities
21 include assisting in overseeing the general books and records of NCSC. In addi-
22 tion, I am responsible for overseeing the technical accounting research within the

1 department and overseeing other ad hoc accounting projects. In carrying out
2 these duties, I am responsible for a number of activities including:

3 (1) Assisting in the maintenance of the accounting system that identi-
4 fies the costs for services that are subsequently billed to NiSource
5 Inc. ("NiSource") affiliates;

6 (2) Developing accounting data, providing testimony, and responding
7 to requests from regulatory bodies with regard to NCSC billing on
8 behalf of the NiSource affiliates.

9 Q: Please state your educational background.

10 A: I received a Bachelor of Science degree in Accountancy in 2004 from Wright
11 State University in Dayton, Ohio.

12 Q: What are your professional credentials?

13 A: I am a Certified Public Accountant and I am currently a member of the American
14 Institute of Certified Public Accountants ("AICPA") and the Ohio Society of
15 Certified Public Accountants ("OSCPA"). I regularly attend accounting and
16 accounting related seminars sponsored by various organizations including
17 AICPA, OSCP and Deloitte.

18 Q: Explain the scope of your testimony in this proceeding.

19 A: The purpose of my testimony is two fold. First, I provide background about
20 NCSC and the role it serves within NiSource. Second, I support the annualized
21 level of NCSC charges applicable to Columbia Gas of Pennsylvania, Inc.
22 ("Columbia") in the historic test year shown in Exhibit 4, Schedule 2, Pages 21-
23 24, and as adjusted for the pro forma future year and fully forecasted rate year

1 shown in Exhibit 104, Schedule 2, Pages 22-31. In supporting that annualized
2 expense level, I provide information pertaining to the types of costs that have
3 been allocated to Columbia and the mechanism for determining the appropriate
4 allocation of each type of cost.

5 **A. THE RELATIONSHIP BETWEEN NCSC AND COLUMBIA**

6 Q: Please explain the structure and role of NCSC.

7 A: NCSC is a subsidiary of NiSource and an affiliate of Columbia within the
8 NiSource corporate organization. NCSC provides a range of services to the
9 individual operating companies within NiSource, including Columbia, and also
10 coordinates the allocation and billing of charges to the NiSource operating
11 companies for services provided by both NCSC directly and by third-party
12 vendors.

13 Q: As Accounting Manager, do you oversee the allocation and billing of affiliate
14 charges?

15 A: Yes, my area is responsible for reviewing general overall charges billed to each of
16 the NiSource affiliates by NCSC. I am also responsible for the accounting system
17 that tracks and identifies the costs for services that are subsequently billed to
18 NiSource affiliates, including Columbia.

19 Q: Please identify the individual corporate affiliates for which NCSC performed
20 services during the test period.

21 A: Exhibit SDC-1 to my testimony lists all affiliates for whom NCSC provided
22 services during the test period.

23 Q: How are the costs billed to affiliates?

1 A: There are two types of billings made to affiliates, including Columbia: 1) contract
2 billing; and 2) convenience billing. Contract billings are identified by job order
3 and represent labor and expenses billed to the respective affiliate. Contract billed
4 charges may be direct (billed directly to a single affiliate) or allocated (split
5 between or among several affiliates), depending on the nature of the expense.
6 Convenience billing reflects payments that are routinely made on behalf of
7 affiliates on an ongoing basis, including employee benefits, corporate insurance,
8 leasing, and external audit fees. Each affiliate is billed on a monthly basis for its
9 proportional share of the payments made in that respective month. As the name
10 implies, convenience billing is intended as a convenience to vendors because it
11 eliminates the need for a separate invoice to be generated for each affiliate entity
12 receiving the same services.

13 Q: Is contract billing rendered pursuant to an executed contract?

14 A: Yes, NCSC has executed an individual Service Agreement with each affiliate,
15 which designates the type of services to be performed and the method of
16 calculating the charges for these services. Services rendered under the Service
17 Agreement are provided at cost, including charges for interest where appropriate.
18 The Service Agreement is updated as needed so that all affiliates that receive
19 service from NCSC are subject to the same modifications, with one exception.¹ A
20 copy of the most recent Service Agreement between NCSC and Columbia was
21 filed with the Pennsylvania Public Utility Commission ("Commission") and

¹ The Virginia State Corporate Commission required inclusion of a Virginia-specific service category that is not included in the Service Agreements for non-Virginia affiliates.

1 approved by Order dated December 15, 2005. A copy of the Service Agreement
2 ("2005 Agreement") is provided as Exhibit SDC-4 to my testimony.

3 Q: Have you prepared an exhibit that summarizes the contract service charges
4 provided to Columbia Gas of Pennsylvania by NCSC?

5 A: Yes, a schedule titled "NiSource Corporate Services Company ("NCSC") Fully
6 Forecasted Rate Year Schedule" is attached hereto as Exhibit SDC-3. Exhibit
7 SDC-3 displays NCSC charges billed to Columbia by Service Category for the test
8 year, adjusted for one-time, non-recurring costs as well as known, pro forma
9 adjustments. This schedule provides further support for the historic, future test
10 year, and fully forecasted test year adjustments shown on Exhibit 4, Schedule 2,
11 Page 21, Exhibit 104, Schedule 2, page 22 and Exhibit 104, Schedule 2, page 27.

12 Q: What services were contract billed to Columbia during the test year?

13 A: Based on the total charges by Service Category as shown in Exhibit SDC-3, the
14 largest dollar categories of services provided to Columbia during the test year
15 were: Information Technology; Customer Billing, Collection and Contact
16 Services; Operations Support and Planning; Accounting and Statistical; Legal;
17 Business Promotion Services; Engineering and Research; Employee Services;
18 Corporate Services; Gas Dispatching; Office Space; and Budget Services. The
19 remaining categories of service made up approximately 8 percent (%) of the total
20 test year billed costs.

21 Q: What functions are provided by Information Technology services?

1 A: Information Technology services generally fall into one of the following
2 categories: client support services, network support services, Customer
3 Information System support services, and computer utilization.

4 These functional areas provide application development, modifications,
5 upgrades, maintenance, and ongoing production support for NiSource's portfolio
6 of systems and software that are used by multiple operating companies, including
7 Columbia. Specific applications used by Columbia include: general ledger,
8 accounts payable, plant accounting, employee information, payroll, and a variety
9 of other mechanized systems.

10 Information Technology is responsible for providing daily operational control,
11 monitoring, data access security, disaster recovery planning, technical research,
12 and budget preparation. This support includes 24 hours per day, 365 days per
13 year support services, problem resolution, development, installation and
14 maintenance of all hardware and software functions needed to operate and
15 control a large scale network computing system. Information Technology is also
16 responsible for ensuring that new functions added to the environment are
17 compatible with the overall structure of the system and will deliver and operate
18 as required. In addition, ongoing evaluation and monitoring of the network
19 computing environment is provided to ensure efficient use of the hardware and
20 timely upgrades to meet the demands of the corporation. This includes reviewing
21 the resources needed for all new applications or major changes to existing
22 applications.

1 Q: What functions are provided by Customer Billing, Collection and Contact
2 Services?

3 A: Services related to Customer Billing include calculating, posting, printing,
4 inserting and mailing customer bills, notices, inserts and similar mailings, as well
5 as bill exception processing and back office processing. Services related to
6 collection include cash processing, revenue recovery, and preparation and
7 management of account receivable aging reports. Contact services include
8 communications with customers regarding commencement, transfer, and
9 disconnection of service, receipt and processing of emergency calls, customer
10 complaints, responses to customer billing, credit, collection, meter reading
11 inquiries, outages, and other inquiries.

12 Q: What functions are provided by Operations Support and Planning Services?

13 A: Operations Support and Planning Services assists with corrosion and leakage
14 programs, estimates of gas requirements and gas availability, gas transmission,
15 measurement, storage and distribution, negotiation of gas purchase and sale
16 contracts, meter testing and repair, and management of transportation and sales
17 programs. These services include regulatory compliance including compliance
18 with environmental, health and safety legislation, as well as environmental
19 project management.

20 Q: What functions are provided by Accounting and Statistical Services?

21 A: Accounting and Statistical Services ("Accounting") provides functions including
22 financial, plant, and regulatory accounting. Accounting is also responsible for
23 maintenance of books and records, accounts payable, accounts receivable, and

1 reconciliations. Accounting's duties include developing, analyzing and
2 interpreting financial statements, preparing data for board of directors' reports,
3 regulatory reports, operating statistics and other internal and external financial
4 reports. Accounting also ensures compliance with Generally Accepted
5 Accounting Principles ("GAAP") by reviewing discussion memos, exposure drafts,
6 financial accounting standards, and interpretations issued by the Financial
7 Accounting Standards Board. Accounting also reviews accounting directives
8 from the Federal Energy Regulatory Commission ("FERC") and state regulatory
9 commissions to ensure compliance with regulatory reporting requirements.
10 Accounting also includes a Consolidation Accounting group, which provides
11 guidance to Columbia and other NiSource affiliates in the setting of accounting
12 policies and procedure development and maintaining a uniform system of
13 accounts. The Consolidation Accounting group reviews new accounting releases
14 from the Financial Accounting Standards Board, the Securities Exchange
15 Commission ("SEC"), FERC, etc., and interprets and assists in implementation.
16 This group also prepares NiSource's financial statements, such as the Annual and
17 Quarterly Report to Stockholders, Form 10-K and 10-Q and other various
18 consolidated financial statements required for financial and regulatory filings.

19 Q: What functions are provided by Legal Services?

20 A: Legal Services includes services provided by attorneys employed by NCSC and
21 fees billed to NCSC by outside legal specialists. Legal services fall into two broad
22 categories. The first category encompasses counsel and representation provided
23 directly to all affiliates, including matters relating to employee benefits and

1 human resources, environmental, financing, general corporate and security
2 matters, and other matters, such as regulatory issues and litigation. The second
3 category encompasses extensive legal support provided to the various NCSC de-
4 partments that in turn provide services to affiliates, as well as services provided
5 directly to affiliates upon request. Included among the NCSC categories to which
6 day-to-day representation is provided are Accounting, Tax, Employee, Rate,
7 Insurance, Information Technology, and Information Services. These specific
8 services include providing advice, recommendations and analyses in the form of
9 legal opinions and memoranda of law, negotiation, drafting and review of agree-
10 ments, contracts and other documents; analyses of the legal implications of
11 actions taken by the SEC, FERC and other state and federal agencies, problem
12 identification and practice of preventive law; and direction and monitoring of
13 outside legal services.

14 Q: What functions are provided by Business Promotion Services?

15 A: Business Promotion Services assists in the development of residential,
16 commercial and industrial business.

17 Q: What functions are performed by Engineering and Research Services?

18 A: Engineering and Research Services assists with estimating costs of construction,
19 designing and scheduling construction plans, and supervising and inspecting
20 construction to ensure safe and reliable, and cost-effective service to Columbia's
21 customers.

22 Q: What functions are provided by Employee Services?

1 A: Employee Services provides both consultative and administrative services to
2 Columbia. These services relate to benefits and compensation design and
3 administration, interpretation of new or pending human resources-related
4 legislation; policy development; temporary labor matters; and coordination of
5 human resources activities.

6 Q: What functions are provided by Corporate Services?

7 A: Corporate Services includes governance of outsourced contracts, proceedings
8 with regulatory bodies, preparation of board resolutions and minutes, filing of
9 legal documents, and other corporate development functions.

10 Q: What functions are provided by Gas Dispatching Services?

11 A: Gas Dispatching Services provides gas control services and managing the delivery
12 of flowing and storage supplies, both sales service and transportation service
13 supplies, within physical constraints and maximum allowed operating pressures.

14 Q: What functions are provided by Office Space and Land/Surveying Services?

15 A: Office Space and Land/Surveying Services are responsible for facility acquisition,
16 and management activities including maintaining and repairing company
17 facilities (including electrical, mechanical, heating and cooling systems),
18 operating and maintaining the buildings and providing a safe and productive
19 working environment for employees.

20 Q: What functions are provided by Budget Services?

21 A: Budget Services is responsible for preparation and development of budgets and
22 budgetary controls.

B. COST ASSIGNMENT TO COLUMBIA BY NCSC

Q: How does NCSC determine charges applicable to Columbia?

A: NCSC was regulated by the SEC under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to FERC. Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with PUHCA 2005 and FERC, NCSC uses a job order system to collect costs that are applicable and billable to affiliates, including Columbia. A job order assigns a 10-digit number to the project(s) involved and details how expenses are to be charged for the project(s). This is the same job order system that has been used by NCSC for many years. Specific projects undertaken by an affiliate are assigned by that affiliate to an existing job order or a new job order is created. Costs are directly charged to a particular affiliate whenever possible. Some job orders necessarily involve more than one affiliate, and in that case, the job order details how expenses are allocated among participating affiliates.

Q. Please explain how costs assigned to a particular job order are allocated.

A. Allocations among affiliates are made only if it is impractical or inappropriate to charge an affiliate directly. Whenever a new job order is created, a decision is made cooperatively by the operating company and NCSC personnel about how

1 costs assigned to that job order will be allocated among participating affiliates.
2 Costs are then assigned using one of the Bases of Allocation described below or
3 direct company codes. Unless a change occurs in the identity of the affiliates
4 participating in a specific job order, costs that are assigned to the job order will
5 be consistently billed by NCSC to its affiliates from that point forward because
6 the job order Bases of Allocation remain the same over time.

7 Q. Please describe the controls in place to ensure that an affiliate is consistently and
8 appropriately billed for a specific job order.

9 A. The job orders are maintained by the NCSC Accounting Department and,
10 therefore, only a few individuals within NCSC Accounting can create or modify
11 job orders. Each job order can be set up with only one Basis of Allocation, and in
12 many cases, only one specific allocation code or direct company billing is set up
13 for a particular job order, depending on what affiliate(s) benefit from the
14 services. If an individual would attempt to use a different Basis of Allocation with
15 a job order that was not selected at inception, the related accounting systems
16 would prompt an immediate error and not allow data to be input.

17 Q: What are the Bases of Allocation?

18 A: NCSC allocates costs for a particular job order in accordance with the following
19 Bases of Allocation that have been previously approved by the SEC and filed
20 annually with the FERC:

21 BASIS 1 - Gross Fixed Assets and Total Operating Expenses

22 BASIS 2 - Gross Fixed Assets

-
- 1 BASIS 7 - Gross Depreciable Property and Total Operating Expenses
2 BASIS 8 - Gross Depreciable Property
3 BASIS 9 - Number of Automotive Units (Owned and Leased)
4 BASIS 10 - Number of Retail Customers
5 BASIS 11 - Number of Regular Employees
6 BASIS 13 - Fixed Allocation
7 BASIS 14 - Number of Transportation Customers
8 BASIS 15 - Number of Commercial Customers
9 BASIS 16 - Number of Residential Customers
10 BASIS 17 - Number of High Pressure Customers
11 BASIS 20 - Direct Costs
-

12
13 A description of each Basis of Allocation is included as Exhibit SDC-2 to my
14 testimony.

15 Q: Are charges for services rendered to Columbia billed at cost?

16 A: Yes, in accordance with the 2005 Agreement (Section 2.2) all services are
17 provided at cost.

18 Q: Please explain each affiliate's rights regarding bills issued by NCSC?

19 A: In accordance with the 2005 Agreement (Section 2.3), affiliates have the right to
20 review and challenge any particular item for which they are billed.

21

22

C. ADJUSTMENTS TO TEST YEAR NCSC ALLOCATION TO COLUMBIA

Q: Have you prepared an exhibit that documents the adjustments to test year NCSC allocations?

A: Yes. Exhibit SDC-3 shows the calculation of the adjustments to test year expense.

Q: Please explain the pro forma adjustments made to the test year NCSC allocations.

A: Three groups of adjustments were made to Historic Test Year NCSC allocations to Columbia. The first group of adjustments were made to eliminate one-time, non-recurring charges in the historical test year and are shown in Columns B through F of Exhibit SDC-3. The one-time, non-recurring charges are broken down into five subcategories (1) labor and benefits, (2) incentive compensation, (3) pension, (4) items deemed non-recoverable, and (5) Deferred NCSC OPEB costs. All charges in these five subcategories were billed to Columbia during the test year and have been adjusted out as non-recurring. The second group of adjustments were made to reflect ongoing NCSC expense levels in the future rate year and are shown in Columns H through M of Exhibit SDC-3. The third group of adjustments were made to reflect ongoing NCSC expense levels at June 30, 2014 for the fully forecasted rate year and are shown in Columns O through T of Exhibit SDC-3.

Q: Please describe the adjustment for labor and benefits added to historical test year expenses.

A: The historic test year labor and benefits adjustment (shown in Column B of Exhibit SDC-3) of \$849,425 is the difference between the total test year labor, payroll tax, and benefits expense billed to Columbia by NCSC, and annualized

1 May 2012 labor expense, and associated payroll taxes and benefits expense,
2 reduced by an amount of labor historically capitalized (19.87%). Annualizing
3 May 2012, the last month of the historic test year, provides the most
4 representative level of ongoing NCSC labor. Detail supporting the labor, payroll
5 tax and benefits expense adjustment is provided on Exhibit 4 Schedule 2 Page 24
6 of 27.

7 Q: Please describe the adjustment for incentive compensation added to historical
8 test year expenses.

9 A: The historic test year per books incentive level was increased by \$88,652 (shown
10 in Column C of Exhibit SDC-3) to reflect the actual level of expense. This
11 adjustment removes any out of period true-ups for the prior year and adjusts the
12 accrual made in the test year to the experienced pay-out level at the claimed
13 capitalization percentage. Detail supporting this historic test year adjustment is
14 provided on Exhibit 4 Schedule 2 Page 22 of 27.

15 Q: Please describe the adjustment for pension added to historical test year expenses.

16 A: The pension adjustment (shown in Column D of Exhibit SDC-3) of \$107,230
17 relates to the amount needed to normalize 2012 calendar year pension expense.
18 The pension cost included for the twelve month test period ending May 31, 2012
19 is lower than pension expense recorded for the 2012 calendar year; therefore, an
20 adjustment was made to reflect the annual pension cost for 2012. This
21 adjustment has the effect of capturing the most recent data from Hewitt,
22 Columbia's program administrator, for the test year. Detail supporting the
23 pension adjustment is provided on Exhibit 4, Schedule 2, Page 23 of 27.

1 Q: Please describe the adjustment for non-recoverable items made to reduce
2 historical test year expenses.

3 A: The non-recoverable items (shown in Column E of Exhibit SDC-3) are comprised
4 of the following items: charitable contributions in the amount of \$(21,653),
5 miscellaneous severances paid out during the test year of \$(16,802), \$(71,426) in
6 promotional advertising expense, \$(7,400) in Dues & Memberships and other
7 miscellaneous one-time adjustments related to vendor payments and job orders
8 of \$(322,486) for which Columbia does not seek recovery. These non-
9 recoverable items result in a net adjustment, totaling \$(439,767).

10 Q: Please describe the adjustment for deferred OPEB costs.

11 A: The NCSC billing adjustment of \$(970,215) (shown in Column F of Exhibit SDC-
12 3) represents items that NCSC billed to Columbia related to deferred NCSC OPEB
13 costs described by Company witness Deborah D. Schmelzer (Columbia Statement
14 No.14).

15 Q: What is the historic test year expense for NCSC contract billings?

16 A: As a result of the foregoing adjustments, the historic test year expense is
17 \$39,821,257 (Column G of Exhibit SDC-3), as shown on page 21 of Exhibit 4,
18 Schedule 2.

19 Q: Please describe the second group of pro forma adjustments that were made to
20 derive the pro forma future test year level of NCSC expenses on Exhibit SDC-3
21 with detail provided on Exhibit 104, Schedule 2, Page 22.

22 A: The first adjustment of \$792,106 (as shown in Column H of Exhibit SDC-3)
23 relates to payroll merit increases and associated payroll tax and benefit increases.

1 The future test year reflects an adjustment for the annual merit increases that will
2 be applied prior to May 31, 2013. Two increases will be applied in the future test
3 year for clerical, exempt and non-union employees. The first increase occurred in
4 June 2012. The second increase will occur in March 2013 as Columbia is
5 adjusting the timing of the normal annual pay increase from June to March. This
6 change reflects management's decision to align the pay increase more closely
7 with the annual performance review discussions held at the end of each calendar
8 year. The timing of the merit increases and the 2.875% merit increase were based
9 on information provided by Columbia's Human Resources - Compensation
10 department for exempt and non-exempt employees. The payroll merit increase
11 adjustment was calculated based upon annualized historic test year labor, and
12 related payroll tax and benefit expense, reduced by an amount of labor
13 historically capitalized (19.87%). Adjusting the annualized May 2012 labor for
14 the merit increases to be experienced in the Future Test Year provides the most
15 representative level of ongoing NCSC labor. Detail supporting the future test year
16 payroll merit adjustment is provided on Exhibit 104 Schedule 2 Page 24 of 31.
17 The second adjustment of \$483,297 (as shown in Column I of Exhibit SDC-3)
18 reflects the increase in incremental O&M costs related to information technology
19 projects of \$298,297 and an increase safety advertising costs of \$185,000 (please
20 refer to R. Ford's testimony in Columbia Statement No. 18 for additional
21 information on the costs associated with this safety advertising program). The
22 increase in incremental O&M costs related to information technology projects of
23 \$298,297 is mainly due to ongoing support of telepresence, wireless and voice

1 over IP related capital information technology projects. The third adjustment of
2 \$(528,525) (as shown in Column J of Exhibit SDC-3) reflects the anticipated
3 decrease in the incentive compensation payout level for 2013 (payable in the fully
4 forecasted rate year) compared to the pro forma historic test year adjusted
5 incentive compensation amount. Detail supporting the future test year Incentive
6 Compensation adjustment is provided on Exhibit 104, Schedule 2, Page 23 of 31.
7 The fourth adjustment of \$121,195 (as shown in Column K of Exhibit SDC-3)
8 reflects an increase for the 2013 estimated level of pension expense compared to
9 the amount included in the historic test year. Detail supporting the future test
10 year pension level is provided on Exhibit 104 Schedule 2 Page 25 of 31. The fifth
11 adjustment of \$1,121,168 (as shown in Column L of Exhibit SDC-3) reflects the
12 anticipated annualized increase in the NCSC costs allocated to Columbia due to
13 adding new full time employees (FTEs) by December 31, 2012. The March 2013
14 merit increase is also added as these new employees will be hired before the
15 effective date of the merit increase. Detail supporting the future test year
16 adjustment is provided on Exhibit 104 Schedule 2 Page 26 of 31. The sixth
17 adjustment of \$426,196 (as shown in Column M of Exhibit SDC-3) reflects the
18 anticipated annualized Future Test Year increase to non-labor costs due to
19 inflationary factors. Non-labor operational and maintenance costs were
20 increased by an inflation index of 1.85%.

21 Q: What is the pro forma future test year level of expense for NCSC contract
22 billings?

1 A: As a result of the adjustments noted above, the pro forma future test year expense
2 level is \$42,236,694 (Column N of Exhibit SDC-3), as shown on page 22 of
3 Exhibit 104, Schedule 2.

4 Q: Please describe the third type of pro forma adjustments made to derive the fully
5 forecasted rate year on Exhibit SDC-3, with detail provided on Exhibit 104,
6 Schedule 2, Page 27.

7 A: The first adjustment of \$439,504 (as shown in Column O of Exhibit SDC-3)
8 relates to a payroll merit increase and associated payroll tax and benefit increases
9 made to reflect a 2.875 percent increase for NCSC employees (including new full
10 time employees hired by December 2012), effective March 1, 2014. The payroll
11 merit increase adjustment was calculated by taking the ending payroll labor, and
12 related payroll tax and benefit expense from the future test year and reduced by
13 an amount of labor historically capitalized (19.87%). Adjusting the pro forma
14 future test year labor for the merit increase to be experienced in the fully
15 forecasted rate year provides the most representative level of ongoing NCSC
16 labor. Detail supporting the fully forecasted test year payroll merit adjustment is
17 provided on Exhibit 104, Schedule 2, Page 29 of 31. In addition, Exhibit 104
18 Schedule 2, Page 29, Lines 21 through 39 calculated the estimated expected
19 impact to rate year expense of the annualized Labor, payroll tax, and benefit
20 adjustment. The second adjustment of \$104,137 (as shown in Column P of
21 Exhibit SDC-3) reflects the anticipated increase in the incentive compensation
22 payout level for 2014 (payable after the fully forecasted rate year) compared to
23 the amount included in the future test year. Detail supporting the fully

1 forecasted rate year Incentive Compensation adjustment is provided on Exhibit
2 104, Schedule 2, Page 28 of 31. In addition, Exhibit 104 Schedule 2, Page 28,
3 Lines 7 through 23 calculated the estimated expected impact to rate year expense
4 of the annualized Incentive Compensation adjustment. The third adjustment of
5 (\$102,498) (as shown in Column Q of Exhibit SDC-3) reflects a decrease to the
6 future test year for the 2014 estimated level of pension expense compared to the
7 amount included in the future test year. Detail supporting the fully forecasted
8 rate year pension level is provided on Exhibit 104 Schedule 2 Page 30 of 31. In
9 addition, Exhibit 104 Schedule 2, Page 30, Lines 6 through 23 calculated the
10 estimated expected impact to rate year expense of the annualized Pension
11 adjustment. The fourth adjustment of \$200,000 (as shown in Column R of
12 Exhibit SDC-3) reflects an increase in incremental O&M costs related to
13 information technology projects mainly due to the forecasted renewal of the
14 Microsoft Enterprise Agreement. The fifth adjustment of \$333,235 (as shown in
15 Column S of Exhibit SDC-3) reflects the anticipated annualized increase in the
16 NCSC costs allocated to Columbia due to adding new full time employees (FTEs)
17 by December 31, 2013. Detail supporting the future test year adjustment is
18 provided on Exhibit 104 Schedule 2 Page 31 of 31. In addition, Exhibit 104
19 Schedule 2, Page 31, Lines 24 through 42 calculated the estimated expected
20 impact to rate year expense of the annualized increase in headcount adjustment.
21 The sixth adjustment of \$375,381 (as shown in Column T of Exhibit SDC-3)
22 reflects the anticipated annualized increase of non-labor costs due to inflationary

1 factors. Non-labor operational and maintenance costs were increased by an
2 inflation index of 1.56%.

3 Q: What is the pro forma fully forecasted rate year level of expense for NCSC
4 contract billings?

5 A: As a result of the adjustments noted above, the pro forma fully forecasted rate
6 year expense level is \$43,586,454 (Column U of Exhibit SDC-3), as shown on
7 page 27 of Exhibit 104, Schedule 2.

8 Q: Please explain the inflation adjustments in Columns M and U of Exhibit SDC-3.

9 A: In a manner similar to adjustments made to various other Columbia direct
10 operation and maintenance costs, the otherwise unadjusted NCSC costs are being
11 inflated in the future test year and fully forecasted rate year as referenced above.
12 The inflation rates used are the same as applied by Witness Gore and detailed in
13 Exhibit No. 104, Schedule 2, Page 21.

14 Q: Please explain the line items at the bottom of Exhibit SDC-3 reflecting amounts
15 shown for regulatory assets and capital.

16 A: The amounts shown as adjustments to NCSC contract billings for regulatory
17 assets and miscellaneous adjustments of \$1,110,071 and capital of \$4,093,803 are
18 items that were billed to Columbia by NCSC and reflect costs that the Columbia
19 accounting staff identified as items that need to be reflected on Columbia's
20 balance sheet. The amounts shown above were made directly on Columbia's
21 books and are necessary to reconcile contract charges billed by NCC during the
22 test year with the test year expenses reflected by Columbia for cost of service
23 purposes.

Q: Does this conclude your prepared direct testimony?

2 A: Yes, it does.

3

NiSource Corporate Services Company

List of Associate Billing Companies

Company Name	Billing Company No.
Columbia Energy Group	11
Columbia Gulf Transmission Company	14
Columbia Energy Services Corporation	15
NiSource Insurance Corporation Limited	22
TPC	24
Columbia Gas of Kentucky, Inc.	32
Columbia Gas of Ohio, Inc.	34
Columbia Gas of Maryland, Inc.	35
Columbia Gas of Pennsylvania, Inc.	37
Columbia Gas of Virginia, Inc.	38
Crossroads Pipeline Company	44
Columbia Gas Transmission, LLC	51
Columbia Remainder Corporation	54
CNS Microwave, Inc.	57
NiSource Inc.	58
Northern Indiana Public Service Company	59
NiSource Development Company, Inc.	60
NiSource Capital Markets, Inc.	62
Energy USA, Inc.	68
PEI Holdings, Inc.	69
NiSource Retail Services, Inc.	71
Service Protection Group, LLC	74
NiSource Finance Corporation	75
NiSource Energy Technology, Inc.	78
Bay State Gas Company	80
NiSource Gas Transmission and Storage Company	82
Energy Interchange, LLC	91
NiSource Energy Ventures, LLC	92
Columbia Gas of Ohio Receivables Corporation	93
Columbia Gas of Pennsylvania Receivables Corporation	94
NIPSCO Accounts Receivables Corporation	95
NiSource Midstream Services, LLC	96
Kennesaw Pipeline, LLC	97

Exhibit A

BASES OF ALLOCATION

The SEC approved Bases of Allocation shown below will be used by the Corporate Services Accounting Department for apportioning Job Order charges to affiliates.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Job order charges will be allocated to each benefited affiliate on the basis of the relationship of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Job order charges will be allocated to each benefited affiliate on the basis of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Job order charges will be allocated to each benefitted affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 20

DIRECT COSTS

- Job order charges will be allocated to each benefitted affiliate on the basis of the relation of its direct costs billed by Service Corporation to the total of all direct costs billed by Service Corporation. All companies may be included in this allocation.

Service Category	Historic Test Year Corporate Billings	Add: Pension Test Year Adjustment	Less: Non-Revocable Items	NCSC DPBE Costs	Normalized Historic Test Bookings	Test Year Labor & Benefits	Add: Incremental OAM	Incentive Compensation Adjustment	Add: 2013 Pension Adjustment	Inflation Adjustment for non-labor costs	NCSC Future Test Year Per Annuity	Test Year Labor & Benefits	Add: 2014 Incentive Compensation Adjustment	Less: 2014 Pension Adjustment	Add: Incremental OAM Costs	Add: New FTEs	Inflation Adjustment for non-labor costs	NCSC Forecasted Rate Year Per Annuity
Accounting and Statistical Services	3,015,984	13,575	16,398	(17,646)	3,163,378	125,534	-	(60,933)	18,520	193,637	3,422,088	60,653	15,917	(5,648)	-	3,542	1,904	3,595,701
Auditing Services	484,668	18,850	2,420	(2,304)	486,094	17,868	-	(15,148)	2,735	1,242	1,662,500	9,758	2,985	(2,913)	-	-	1,094	1,698,032
Budget Services	949,454	3,570	5,028	(9,390)	945,092	37,150	-	(71,281)	5,737	3,016	1,055,852	20,618	4,193	(4,852)	-	-	1,094	1,098,266
Business Promotion Services	1,974,887	72,865	1,176	(87,481)	1,964,153	73,935	-	(98,760)	11,003	7,063	1,930,972	41,023	8,428	(9,813)	-	-	6,221	2,019,633
Corporate Services	1,672,152	24,067	8,286	(24,067)	1,672,152	39,992	-	(48,561)	5,881	11,311	1,870,975	22,190	4,298	(4,973)	-	-	9,963	1,717,850
Customer Billing, Collection, and Contact Services	6,034,467	85,339	4,934	(10,980)	6,134,425	70,581	-	(92,454)	11,743	8,234	6,278,569	44,156	5,766	(9,932)	-	-	72,430	6,391,018
Employee Services	1,474,140	54,319	7,041	(7,041)	1,486,472	51,135	-	(39,554)	7,413	6,547	1,510,882	28,373	6,493	(6,769)	-	-	5,786	1,553,245
Engineering and Research Services	55,275	2,947	6,558	(7)	1,297,926	11,489	-	(17,568)	8,335	3,034	1,343,326	28,574	3,481	(7,134)	-	-	2,673	1,370,901
Facilities and Support Services	55,275	2,947	1,907	(1,907)	323,499	11,600	-	(11,301)	1,605	754	326,137	6,308	2,666	(1,527)	-	-	648	333,960
Financial Services	1,222,886	55,275	1,907	(1,907)	1,222,886	13,981	-	(13,351)	2,181	4,281	1,267,914	7,758	2,666	(1,643)	-	-	1,871	1,286,284
Information Technology Services	1,550,738	2,929	1,907	(1,907)	1,550,738	3,414	-	(3,414)	4,403	20,618	1,568,760	18,656	3,922	(3,771)	-	-	13,664	1,585,683
Insurance Services	11,844,093	3,348	3,923	(3,923)	11,844,093	258,297	-	(3,636)	7,272	87,090	12,731,420	18,656	2,666	(3,771)	-	-	13,664	12,765,884
Interest, Stock, and Tax	2,188,764	810	584	(62,750)	2,135,768	4,351	-	(41,592)	6,096	41,092	1,948,881	2,414	716	(368)	-	-	34,193	1,933,093
Legal Services	42,773	7,816	5,594	(41,922)	1,763,146	59,887	-	(48,569)	6,702	15,033	1,823,309	22,131	9,181	(5,156)	-	-	12,241	1,862,707
Office Support	13,400	969	1,560	(1,560)	732,772	12,504	-	(5,658)	1,807	8,546	740,672	6,938	1,174	(1,528)	-	-	7,526	763,781
Operations Support and Planning Services	7,719,744	21,404	45,591	(62,989)	8,147,300	377,628	-	(199,342)	51,529	1,062,714	14,437	9,440	33,366	(43,579)	-	-	12,715	10,032,258
Procurement, Storage and Disposition Services	640,485	2,884	3,367	(418)	672,115	24,813	-	(13,031)	3,068	2,983	686,085	13,657	2,686	(3,219)	-	-	1,834	703,943
Rate Services	165,278	7,881	1,243	(1,938)	194,277	7,103	-	(7,412)	1,147	341	195,516	3,674	1,460	(970)	-	-	300	200,281
Tax Services	381,178	15,375	1,975	(8,509)	403,106	15,270	-	(12,468)	2,232	914	409,056	8,473	2,457	(1,868)	-	-	605	418,902
Transportation Services	583,276	12,330	937	(1,041)	588,133	11,498	-	(5,506)	1,912	6,344	612,290	6,300	1,101	(1,417)	-	-	5,587	623,790
Training Services	378,659	10,091	1,350	(1,350)	392,471	9,688	-	(39,471)	35,478	426,196	47,102,991	548,469	2,154	(1,420)	-	-	5,274	464,278
Subtotal	44,176,382	1,007,057	110,635	(430,787)	44,314,122	998,320	483,297	(608,585)	151,248	1,399,187	47,102,991	548,469	129,061	(127,914)	200,000	415,866	375,381	48,644,778
Less: Reg Assets Capitalized	(4,003,803)	(210,832)	-	-	(4,214,635)	(196,420)	-	-	(300,053)	(276,019)	(4,411,065)	(196,420)	-	-	-	-	-	(4,607,485)
Less: Reg Assets & Mac Adj on CPA	(1,110,071)	-	67,095	-	(1,042,976)	-	-	131,000	(300,053)	(276,019)	-	-	(25,823)	25,416	-	-	-	(1,042,976)
Total	30,212,718	689,424	88,652	107,230	30,817,257	792,106	483,297	(528,525)	121,195	1,121,168	42,236,064	439,504	104,137	(102,498)	200,000	333,235	375,381	43,585,434

Service Agreement
BETWEEN
NISOURCE CORPORATE SERVICES COMPANY
AND
COLUMBIA GAS OF PENNSYLVANIA, INC.

Dated December 15, 2005
(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into this 17th day of December, 2005 by and between Columbia Gas of Pennsylvania, Inc., its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, the Securities and Exchange Commission ("SEC") has approved and authorized as meeting the requirements of Section 13(b) of the Public Utility Holding Company Act of 1935 ("Act") the organization and conduct of the business of the Company, in accordance herewith, as a wholly-owned subsidiary service company of NiSource Inc. ("NiSource"), including the allocation of all Company costs by using the methods approved by the Securities and Exchange Commission ("SEC Method");

WHEREAS, Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at cost, with cost determined in accordance with applicable rules and regulations under the Act, which require the Company to fairly and equitably allocate costs among all Clients to which it renders services; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client,

for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with the SEC Method. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably allocated, all in accordance with the requirements of the Act and any orders promulgated thereunder. The Company shall review with the Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall render a monthly report to Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake an immediate review of the report and identify all questions or concerns

regarding the charges reflected within ten (10) days of receipt of the report. If no concerns are identified within that time, Client shall remit to the Company all charges billed to it within 30 days of receipt of the monthly report.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and the SEC, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the SEC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 On an annual basis, the Company and Client shall meet to assess the quality of the Services being provided pursuant to this Service Agreement and to determine the continued need therefor and shall, subject to Section 1.1, above, amend the scope of services, delete services entirely from this Service Agreement, and/or decline services as they determine to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the General Rules and Regulations promulgated by the SEC pursuant to the Act, in particular, the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies in effect from and after the date hereof.

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed
as of the date and year first above written.

NISOURCE CORPORATE SERVICES
COMPANY

By: Susanne M. Taylor
Name: Susanne M. Taylor
Its: Controller

COLUMBIA GAS OF PENNSYLVANIA, INC.

By: Terrence J. Murphy
Name: Terrence J. Murphy
Its: President

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

- 1 The term "Company" shall mean NiSource Corporate Services Company and its successors.
- 2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.
- 3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company will advise and assist the Clients in all aspects of accounting, including financial accounting, plant accounting, regulatory accounting, tax accounting, maintenance of books and records, safeguarding of assets, accounts payable, accounts receivable, reconciliations, accounting research, reporting, operations and maintenance analysis, and related accounting functions. The Company will also provide services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company will ensure compliance with generally accepted accounting principles and provide guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company will advise and assist the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants in the annual examination of their accounts.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of budgets and budgetary controls.

4 *Business Promotion Services.* The Company will advise and assist the Clients in the preparation and use of advertising, in the development of residential, commercial and industrial business, and in the rendering of aid to local appliance distributors and dealers in the advertising and promotion of appliance sales.

5 *Corporate Services.* The Company will advise and assist the Clients in connection with corporate matters and with proceedings involving regulatory bodies.

6 *Depreciation Services.* The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

7 *Economic Services.* The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

8 *Electronic Communications Services.* The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

9 *Employee Services.* The Company will advise and assist the Clients in connection with employee relations matters, including recruitment, employee placement, training, compensation, safety, labor relations and health, welfare and employee benefits. The Company will also advise and assist the Clients in connection with temporary labor matters, including assessment, selection, contract negotiation, administration, service provider relationships, compliance, review and reporting.

10 *Engineering and Research Services.* The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, engineering and supervision of the fabrication of natural gas facilities, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

11 *Gas Dispatching Services.* The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

12 *Information Technology Services.* The Company will advise and assist Clients in matters involving information technology, including management, operations, control, monitoring, testing, evaluation, data access security, disaster recovery planning, technical research, and support services. The Company will also provide and assist the Client with application development, maintenance, modifications, upgrades and ongoing production support for a portfolio of systems and software that are used by the Clients. In addition, the Company will identify and resolve problems, ensure efficient use of software and hardware, and ensure that timely upgrades are made to meet the demands of the Clients. The Company will also maintain information concerning the disposition and location of Information Technology assets.

13 *Information Services.* The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

14 *Insurance Services.* The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

15 *Legal Services.* The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice (relating to the all aspects of SEC compliance, PUHCA, FERC, FPA, PURPA), bankruptcy and collection matters, employment and labor relations investigations, union contracting, EEOC issues, and all other matters for which Clients require such legal services.

16 *Office Space.* As may from time to time be available, the Company will provide suitable space in its offices for the use of the Clients and their officers and employees.

17 *Officers.* Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

18 *Operations Support and Planning Services.* The Company will advise and assist the Clients in connection with operations support and planning, including logistics and scheduling; workforce planning; corrosion and leakage programs; estimates of gas requirements and gas availability; gas transmission, measurement, storage and distribution; construction requirements; construction management; operating standards and practices; regulatory compliance; training; management of transportation and sales programs; negotiation of gas purchase and sale contracts; energy marketing and trading; security services; measurement, regulation and conditioning equipment; meter testing, calibration and repair; hydraulic gas network modeling, facility mapping and GIS technologies; and other operating matters.

19 *Purchasing, Storage and Disposition Services.* The Company will render advice and assistance to the Clients in connection with supply chain activities, including the standardization, purchase, lease, license and acquisition of equipment, materials, supplies, services, software, intellectual property and other assets, as well as shipping, storage and disposition of same. The Company will also render advice and assistance to the Client in connection with the negotiation of the purchase, sale, acquisition or disposition of assets and services and the placing of purchase orders for the account of the Client.

20 *Rate Services.* The Company will advise and assist the Clients in all rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings of producers and pipeline suppliers, and the preparation and presentation of testimony and exhibits to regulatory authorities.

21 *Tax Services.* The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

22 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

23 *Treasury Services.* The Company provides services such as cash management, long and short term financing for NiSource and all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, special economic studies as requested, and support for various regulatory proceedings, as requested.

24 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

25 *Customer Billing, Collection, and Contact Services.* The Company will render calculating, bill exception processing, back office processing, posting, printing, inserting, mailing and related services to Client associated with the preparation and issuance of customer bills, notices, inserts and similar mailings. The Company will provide cash processing, revenue recovery, account reconciliations and adjustments, and related services to Client associated with the collection of revenue and management of accounts receivable. The Company will provide customer contact and related services to Client, including customer contact center management, operation and administration; management of key customer relationships; communications associated with the commencement, transfer, maintenance and disconnection of service; sales of optional products and services; the receipt and processing of emergency calls; the handling of customer complaints; and responses to customer billing, credit, collection, order take and inquiry, outage, meter reading, retail choice and other inquiries.

26 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, as may properly be rendered by the Company to such Client

within the meaning and intent of the Public Utility Holding Company Act of 1935 and any other applicable statutes and the orders, rules and regulations of the Securities and Exchange Commission and any other governmental bodies having jurisdiction, as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method approved by the Securities and Exchange Commission as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses which are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall be apportioned among the Clients, as applicable, in the proportions which the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

BASES OF ALLOCATION

The SEC approved Bases of Allocation shown below will be used by the Corporate Services Accounting Department for apportioning Job Order charges to affiliates. Any change in an allocation method that causes either a \$50,000 or 5% change in the cost that would be charged to a company must be brought to the SEC for approval under the 60-Day Letter process.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Job order charges will be allocated to each benefited affiliate on the basis of the relationship of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Job order charges will be allocated to each benefited affiliate on the basis of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Job order charges will be allocated to each benefitted affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 20

DIRECT COSTS

- Job order charges will be allocated to each benefitted affiliate on the basis of the relation of its direct costs billed by Service Corporation to the total of all direct costs billed by Service Corporation. All companies may be included in this allocation.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

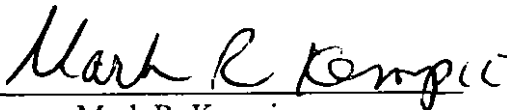
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Mark R. Kempic, being President of Columbia Gas of Pennsylvania, Inc. ("Columbia"), hereby state that the testimony set forth in Columbia Statement Nos. 1 and 101-R are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Mark R. Kempic

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

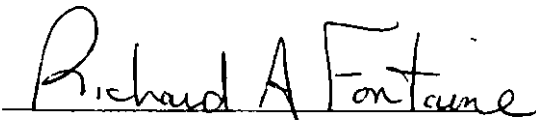
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
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Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Richard Fontaine, being Vice President, Financial Transformation, of NiSource Corporate Services ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 13 is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Richard Fontaine

2-13-13

Hbg 89

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

DIRECT TESTIMONY OF
RICHARD FONTAINE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Richard Fontaine. My business address is 200 Civic Center Drive,
3 Columbus, Ohio 43215.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by NiSource Corporate Services as Vice President, Financial
6 Transformation.

7 Q. What are your responsibilities as Vice President, Financial Transformation?

8 A. I am responsible for leading the NiFiT project.

9 Q. What is your educational and professional background?

10 A. Professionally, I have worked for 38 years with finance and accounting processes
11 and systems both in industry and as a consultant. My education was at The Ohio
12 State University from which I hold a Masters Degree in Business Administration.
13 I am also a Certified Public Accountant in the State of Ohio (inactive status).

14 Q. Have you previously testified before this or any other state commission?

15 A. No.

16 Q. Please describe the scope of your testimony in this proceeding.

17 A. I will explain "NiFiT", which is a NiSource project designed to upgrade financial
18 processes and information systems across all of the NiSource companies,
19 including Columbia Gas of Pennsylvania, Inc. ("Columbia"). My testimony will
20 also provide the rationale behind the NiFiT project, the benefits from and project
21 timeline for NiFiT, and the expected capital and O&M costs to Columbia for
22 NiFiT.

23 Q. What is NiFiT?

1 A. NiFiT is a NiSource initiative to install new computer software that will enable
2 NiSource to adopt common financial processes and systems. The primary focus
3 of NiFiT is to implement a common general ledger and chart of accounts for all
4 NiSource companies. Currently, NiSource uses four separate general ledger
5 software packages, three of which are no longer supported by their respective
6 vendors, including the GEAC package used by Columbia.

7
8 NiFiT requires an extensive redesign and replacement of existing computer
9 software programs. This investment is intended to ensure that the NiSource
10 companies, including Columbia, will be able to continue executing strong
11 accounting data integrity, operational efficiencies and internal and external
12 financial reporting to serve the needs of all its stakeholders. Through NiFiT, the
13 NiSource companies will standardize, automate and drive process improvements
14 in financial reporting and analysis, as well as financial controls.

15
16 Examples of these process improvements include but are not limited to:

- 17 - Mechanized inter-company billings
- 18 - Increased mechanized account reconciliations
- 19 - Ability to generate detailed Generally Accepted Accounting Principles (GAAP)
20 financial statements, Federal Income Tax financial statements, and
21 Regulatory financial statements mechanically
- 22 - Automated approval processes with audit trail
- 23 - Improved account validation reducing the amount of manual intervention

1 Q. Please explain the business need for the NiFiT project.

2 A. The need for the project is driven by the age and operating risk of the current
3 financial systems in use by the NiSource companies. The software versions of
4 three of our four general ledger packages are no longer being upgraded or
5 supported by their respective vendors, and there is limited internal or external
6 information technology ("IT") systems knowledge to maintain them. In addition,
7 having multiple different general ledgers, charts of accounts, and accounting
8 processes in use across the NiSource system creates inefficiencies for the
9 financial staffs of the NiSource companies.

10 Q. Please elaborate on the impact of NiFiT on Columbia?

11 A. As I previously noted, Columbia currently uses GEAC, a mainframe system, as its
12 general ledger and accounts payable software package. GEAC is also the primary
13 source of financial expenditure information for Columbia's project and
14 department managers. Although the GEAC software has operated sufficiently,
15 the software is now obsolete.

16 Q. Why is Columbia's GEAC software obsolete?

17 A. The GEAC software system was developed in the 1980's, was originally
18 implemented at Columbia in 1993, and was last upgraded in 1999. The vendor
19 that created GEAC has changed hands several times, and the system is no longer
20 offered for sale or supported by the vendor. The system was also modified and
21 customized over the years to address Columbia's specific needs. As a result of its
22 age, the IT resources needed to support GEAC are difficult to obtain. This loss of
23 vendor support and the scarcity of IT knowledge to operate and maintain GEAC

1 are of concern, as is the fact that GEAC is expected to require significant
2 modifications over the next few years to support compliance with the
3 International Financial Reporting Standards ("IFRS").

4 Q. Please describe how the NiFiT project will address GEAC and the other general
5 ledger software systems used by the NiSource companies.

6 A. Through NiFiT, GEAC and the other general ledger software systems will be
7 replaced with PeopleSoft Financials, which includes general ledger, accounts
8 payable, project costing, and financial reporting software. A new, common chart
9 of accounts will be implemented, and hardware upgrades necessary to run
10 PeopleSoft will be made. In addition, the PeopleSoft software will integrate with
11 many of Columbia's existing software systems, including asset management,
12 work management, and time and labor software. This will provide an efficient
13 business environment to support Columbia's operations.

14
15 NiSource determined that PeopleSoft Financials would be the most cost effective
16 software selection for standardizing our financial processes and systems because
17 PeopleSoft is one of the three software packages that are commonly used in North
18 American utilities. It has a solid reputation, roughly comparable features to the
19 other leading packages (Oracle Enterprise Business System and SAP), and a
20 significant market share (which is important for obtaining support personnel).

21 In addition, the corporation already owns licenses for most of the relevant
22 PeopleSoft application modules, and an older version of PeopleSoft is already in
23 use and familiar to the finance and accounting staff in two of the NiSource

1 companies so the transition would be easier than to one of the alternative
2 packages.

3 Q. Please describe the benefits of the software system upgrades being implemented
4 through the NiFiT project.

5 A. In short, the successful implementation of the NiFiT project will help ensure that
6 the NiSource companies, including Columbia, continue to execute strong
7 financial controls and operating efficiencies. The installation of PeopleSoft
8 Financials will transform the current financial processes and systems, which are
9 obsolete, and no longer have vendor support, to current technology platforms
10 which will reduce the risk of failure for existing systems, such as GEAC, where
11 there is no vendor support available.

12
13 In addition, NiFiT will standardize financial processes and financial data for
14 employees across the NiSource companies; increase Sarbanes-Oxley controls
15 automation; provide easier access to information for analysis of the cost of
16 projects for managers across the companies; and automate NiSource Corporate
17 Services Company's (NCSC) allocation and billing of charges to the NiSource
18 companies for services provided by both NCSC directly and by third-party
19 vendors.

20
21 Q. What is the timeline for implementing NiFiT?

22 A. It is expected that NiFiT will become available across NiSource in phases through
23 2015. For Columbia, PeopleSoft Financials is planned to be placed into service in

1 April 2014. Conducting the NiFiT initiative on a centralized basis enables
2 Columbia and the other NiSource affiliates to realize economic and quality
3 benefits through efficient use and availability of specialized personnel and
4 equipment, and coordination of analysis and design tasks, which Columbia could
5 not as economically obtain on an individual company basis.

6
7 Q. What are the expected capital costs for Columbia?

8 A. The total cost of the NiFiT project is expected to be approximately \$115 million to
9 \$125 million. Of this total, O&M is expected to be approximately 33% or \$38 to
10 \$41 million; Capital is expected to be approximately 67% or \$77 to \$84 million.

11
12 Approximately 20% of the total cost is expected to be internal labor;
13 approximately 64% is expected to be external labor; and 16% is expected to be
14 non-labor costs (such as computer hardware and software, project facilities,
15 travel costs, materials and supplies, etc.).

16
17 Columbia's total expected share of capital cost associated with NiFiT for replacing
18 GEAC with the PeopleSoft Financials software will be approximately \$4.037
19 million. About 3% of these costs were incurred in 2011, 42% are planned for
20 2012, 32% are planned for 2013, and 23% are planned for 2014. This is an
21 estimate based on current work plans. Actual costs are being tracked and
22 recorded as incurred and may vary from this estimate.

23 Q. What are the expected O&M costs for Columbia?

1 A. Columbia will incur non-recurring NiFiT project costs primarily related to project
2 management, training and data conversion. These costs are being expensed in
3 accordance with GAAP Accounting Standards Codification 350-40.

4
5 Columbia's total expected non-recurring O&M cost associated with NiFiT is
6 expected to be approximately \$2.020 million. About 7% of these costs were
7 incurred in 2011, 30% are planned for 2012, 17% are planned for 2013, and 46%
8 are planned for 2014. This is an estimate based on current work plans. Actual
9 costs are being tracked and recorded as incurred and may vary from this
10 estimate.

11 Q. How are the NiFiT project costs being captured and allocated to CPA?

12 A. Each project deliverable is tagged in our project work plan to an accounting
13 charge code. This code indicates whether the work associated with each
14 deliverable is O&M or Capital, and whether the deliverable is associated with a
15 single company or will be shared by more than one. If the deliverable is shared,
16 the code indicates which companies share it. By tagging the deliverables in this
17 way, we provide consistent instructions to the project team individuals about how
18 they should account for their time. That is, all they need to know in order to
19 accurately record their time is what deliverable they are working on and for how
20 long – much like a field crew simply has to know what work order or service
21 order they are performing. The project team individuals then record how much
22 time they worked by accounting charge code in our project work plan system.
23 Similarly, project invoices for purchased goods or services are coded with the

1 appropriate accounting charge code when they are approved.

2
3 Based on the accounting charge code, NiFiT costs that are separately identified as
4 incurred for a particular company will be direct charged to that company,
5 including Columbia. Design and implementation costs that are identified as
6 incurred for the benefit of multiple companies will be allocated to those
7 companies using a combination of NCSC allocation billing methods previously
8 approved by the SEC.

9 Q. Will your testimony be supporting the revenue requirement associated with the
10 NiFiT project?

11 A. No, Mr. Gore's testimony provides the supporting information related to the
12 revenue requirement for the NiFiT project.

13 Q. Does this conclude your testimony?

14 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

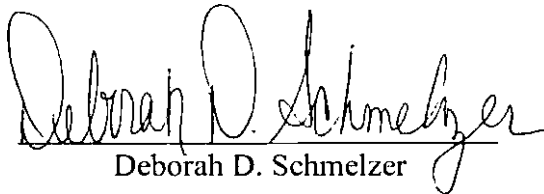
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Deborah D. Schmelzer, being Project Manager of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 14 is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Attachments A and B, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11th, 2013


Deborah D. Schmelzer

[illegible]

SEPTEMBER 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Deborah D. Schmelzer. My business address is 200 Civic Center
3 Drive, Columbus Ohio 43215.

4 Q. What is your position of employment?

5 A. I serve as Project Manager for NiSource Corporate Services Company ("NCSC"),
6 which provides a variety of corporate services to the NiSource distribution
7 companies, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the
8 Company").

9 Q. Please describe your professional and educational background.

10 A. I began my career in 1991 as an auditor with the public accounting firm of Arthur
11 Andersen LLP. In 1999, I left public accounting to join a telecommunication
12 company where I held various positions in the accounting and finance
13 organization, including Corporate Controller, Director of Finance and Vice
14 President of Finance. In December 2002, I resigned from the
15 telecommunications company to pursue part-time employment. Prior to joining
16 NCSC, I held a part-time accounting and business administration position at a
17 non-profit organization. In 2011, I joined NCSC as a lead financial analyst and
18 was assigned to my current position in May, 2012.

19 Q. Please describe your educational background and professional credentials.

20 A. In 1991, I graduated from Ohio University with a Bachelor of Business
21 Administration, majoring in Accounting. I am a Certified Public Accountant and
22 a member of the Ohio Society of Certified Public Accountants.

1 Q. Have you previously testified before the Pennsylvania Public Utility Commission
2 (the "Commission") or any other regulatory commission?

3 A. No, I have not.

4 Q. What is the purpose of your testimony?

5 A. The purpose of my testimony is to sponsor certain exhibits in the proceeding.

6 Q. What Exhibits in this proceeding are sponsored by you?

7 A. I am sponsoring the exhibits relating to the past and anticipated changes in major
8 accounting procedures since the previous rate case, the Other Post Employment
9 Benefits ("OPEB") base rate reconciling mechanism, and the amortization of the
10 deferred NCSC OPEB-related costs. Specifically, I am sponsoring Exhibit No. 4,
11 Schedule No. 2, page 26, Exhibit No. 4, Schedule No. 16 (38), Exhibit No. 104,
12 No. Schedule 9 (38), and Exhibit No. 104, Schedule No. 2, page 13 and page 14.

13 Q. What test years will you be addressing in this testimony?

14 A. I will be addressing the twelve-month period ending May 31, 2012 as the Historic
15 Test Year, the twelve-month period ending May 31, 2013 as the Future Test Year,
16 as well as the Fully Forecasted Rate Year as the twelve-month period ending June
17 30, 2014.

18 Q. What are the past and anticipated changes in major accounting procedures and
19 what is the financial statement impact?

20 A. In 2012, Columbia adopted Accounting Standards Update (ASU) 2011-05, which
21 revised the manner in which entities present comprehensive income in their
22 financial statements. Specifically, by adopting ASU 2011-05, Columbia now

1 presents the Statement of Income and the Statement of Comprehensive Income
2 as two separate but consecutive statements for external reporting purposes.

3 In December 2011, the FASB issued ASU 2011-11, which requires additional
4 disclosures regarding the nature of an entity's right to offset positions associated
5 with its financial and derivative instruments. Columbia is currently reviewing the
6 provisions of ASU 2011-11 to determine the impact on its financial statements.

7 Q. Please describe the reconciling mechanism that was approved for OPEB.

8 A. The base rate reconciling mechanism permits Columbia to defer the difference
9 between the annual OPEB costs calculated pursuant to FASB Accounting
10 Standards Codification ("ASC") 715, "Compensation-Retirement Benefits" (SFAS
11 No. 106) and the annual OPEB allowance included in rates. Only those amounts
12 attributable to operation and maintenance expense are deferred and recognized
13 as a regulatory asset or liability pursuant to the provisions of ASC 980,
14 "Regulated Operations." Amounts recorded as a regulatory asset or liability are
15 to be collected from or returned to customers in the next rate proceeding using an
16 appropriate amortization period. In subsequent base rate proceedings, the
17 prospective base rate allowance for OPEB costs will be reset to reflect the then-
18 current OPEB expense level. Pursuant to the settlement under which this
19 mechanism was adopted, Columbia has committed to deposit into trusts the
20 actual annual OPEB accrual.

21 Q. How much was Columbia authorized to collect for OPEB expense in its last base
22 rate proceeding?

1 A. In the Settlement, Columbia's annual OPEB expense allowance in rates was
2 stated to be \$1,898,955.

3 Q. Did Columbia utilize \$1,898,955 to calculate the deferral for the OPEB base rate
4 reconciling mechanism?

5 A. Yes.

6 Q. How much has Columbia deferred for the base rate reconciling mechanism as of
7 the end of the historic test year ended May 31, 2012?

8 A. As of the end of the Historic Test Year, Columbia has deferred \$1,123,372 as a
9 regulatory liability to be passed back to its customers.

10 Q. How much does Columbia anticipate deferring for the base rate reconciling
11 mechanism as of June 30, 2013?

12 A. Columbia anticipates an approximate \$607,393 regulatory liability deferral as of
13 June 30, 2013 as detailed in Exhibit No. 104, Schedule No. 2, pages 13 and 14 of
14 31.

15 Q. How does Columbia propose to pass this amount back to its customers?

16 A. Columbia proposes to pass-back this over-collection over a two-year period. This
17 pass-back is detailed in the Future Test Year on Exhibit No. 104, Schedule No. 2,
18 page 11 of 31 and in the Fully Forecasted Rate Year on Exhibit No. 104, Schedule
19 No. 2, page 12 of 31 as a reduction to benefits expense and therefore is included in
20 the revenue requirement calculation for this case.

21 Q. Does Columbia propose to continue the deferral treatment?

22 A. Columbia proposes to continue the deferral treatment but with a modification.
23 In prior years, the ongoing medical and group life OPEB expense was a positive

(debit) amount. A large portion of the expense was the amortization of the transition obligation; however, the amortization of the transition obligation will end in December 2012. The 2013 ongoing medical and group life OPEB expense, as determined by the actuary, will be a negative (credit) amount. However, Columbia cannot withdraw cash from the trusts to pay itself for these negative (credit) amounts. Because this negative (credit) expense is non-cash, Columbia is claiming zero expense for ongoing medical and group-life OPEB expense in the Future Test Year, as shown on Exhibit No. 104, Schedule No. 2, page 11 of 31, and in the Fully Forecasted Rate Year, as shown on Exhibit No. 104, Schedule No. 2, page 12 of 31. Although the claim is zero, Columbia will track the annual medical and group life OPEB expense. To the extent that the cumulative annual expense is positive in the future, Columbia will record a regulatory asset equal to the cumulative positive expense and seek recovery of the regulatory asset in its next rate case, pursuant to the terms of the reconciling mechanism. To the extent that the cumulative annual expense is negative, no action will be required because the negative expense is non-cash; therefore, there will be no pass-back of negative expense.

This change in the deferral treatment does not change the pass-back of the prior over-collection; the prior over-collection will be passed back over two years as described above.

Q. Does Columbia currently deposit OPEB amounts into a trust?

1 A. Yes, it does. Columbia has established a Voluntary Employees' Beneficiary
2 Association ("VEBA") trust, into which Columbia has deposited amounts for
3 OPEBs since the early 1990s.

4 Q. How does Columbia plan to fund the trust?

5 A. Under Columbia's funding policy, Columbia deposits the gross annual OPEB
6 accrual into the OPEB trust. Because the gross OPEB accrual beginning in 2013
7 is expected to be a negative expense (credit), no funding is anticipated in 2013.
8 Columbia will continue to pay OPEB benefits from the trust.

9 Q. Please describe the amortization of the deferred NCSC OPEB-related costs on
10 Exhibit No. 4, Schedule No. 2, page 26 of 27.

11 A. Pursuant to the Opinion and Order entered on May 24, 2012 in Docket No. P-
12 2011-2275383, Columbia deferred, for accounting and financial reporting
13 purposes, the one-time expense of \$903,131 associated with its allocated share of
14 NCSC's OPEB regulatory asset resulting from NCSC's transition from cash basis
15 to accrual. See Attachment A for Columbia's Petition and Attachment B for the
16 Opinion and Order.

17 This Opinion and Order did not preclude Columbia from seeking recovery of the
18 total amount deferred. Columbia proposes to recover the total deferred amount
19 of \$903,131 over a ten-year period.

20 Q. What amount is included in the revenue requirement for this amortization?

21 A. The annual amortization of \$90,313 is included on Exhibit No. 4, Schedule No. 2,
22 page 26 of 27.

23 Q. Why does Columbia seek to recover this amortization amount?

1 A. As described in Columbia's Petition to the Commission, NCSC previously billed
2 Columbia for NCSC employees' OPEB costs on a claims paid basis. For financial
3 accounting purposes, NCSC did adopt SFAS No. 106 in January, 1991, and
4 recorded expense calculated in accordance with that accrual method. However,
5 because NCSC only billed affiliates based upon claims paid, it recorded the
6 difference between the accrual amount and cash as a deferred amount on its
7 books. That difference totaled \$9,883,242 at December 31, 2010.

8 In June 2011, NCSC determined that it would change its billing to affiliates to an
9 accrual basis, with a funded OPEB trust. This was a result of a determination
10 that NCSC could no longer continue to record a deferral for the difference
11 between SFAS No. 106 accrual and cash claims paid. As part of the changeover
12 from cash to accrual, NCSC billed the entire regulatory asset balance as of
13 December 31, 2010 to the NiSource subsidiaries, including Columbia, in June
14 2011. Columbia's share of that billing is \$970,216. Columbia capitalized
15 approximately \$67,085 of this amounts to reflect that had these costs been billed
16 to Columbia over time, a portion would have been allocated to capital projects.
17 The remaining \$903,131 was recorded as a regulatory asset. The entire billed
18 amount was funded in a trust in September of 2011.

19 The changeover from billing the affiliates on a cash basis to an accrual basis is a
20 one-time, non-recurring event. As such, it is appropriate for Columbia to be
21 permitted to recover the cost as an amortization. In addition, as explained in the
22 Petition, the changeover from cash to accrual accounting satisfies the
23 Commission's Policy Statement on utilities' converting from cash to accrual

1 accounting for SFAS No. 106 costs. Consistent with that Policy Statement, and
2 the Commission's decision to allow Columbia to recover the deferral of its own
3 transition obligation when Columbia changed from cash to accrual accounting for
4 ratemaking purposes, Columbia should be permitted to recover the amount it
5 was billed as part of the transition of NCSC from cash to accrual for OPEB costs.

6 Q. Does this conclude your Prepared Direct Testimony?

7 A. Yes.



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Andrew S. Tubbs

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File #: 126871

November 29, 2011

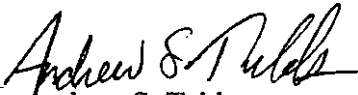
Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

**RE: Petition of Columbia Gas of Pennsylvania, Inc. For Authorization to Defer, For
Accounting Purposes, Certain Costs Associated With A Regulatory Asset Related to
Other Post-Retirement Benefits Provided By NiSource Corporate Service Company
Docket No. P-2011-**

Dear Secretary Chiavetta:

Enclosed for filing is the Petition of Columbia Gas of Pennsylvania, Inc. in the above-referenced proceeding. Copies have been provided to the parties as indicated on the Certificate of Service.

Respectfully Submitted,


Andrew S. Tubbs

AST/jl
Enclosures
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA FIRST CLASS MAIL

Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923

Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
PO Box 3265
Harrisburg, PA 17105-3265

Office of Small Business Advocate
Commerce Building
300 North Second Street, Suite 1102
Harrisburg, PA 17101

Date: November 29, 2011



Andrew S. Tubbs

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Columbia Gas of Pennsylvania, :
Inc. For Authorization to Defer, For :
Accounting Purposes, Certain Costs : Docket No. P-2011-_____
Associated With A Regulatory Asset :
Related to Other Post-Retirement Benefits :
Provided By NiSource Corporate Service :
Company :

PETITION OF COLUMBIA GAS OF PENNSYLVANIA, INC.

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

I. INTRODUCTION

Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") hereby petitions the Pennsylvania Public Utility Commission ("Commission"), pursuant to Section 1701 of the Public Utility Code, 66 Pa. C.S. § 1701, for authority to defer, for accounting and financial reporting purposes, costs related to Other Post-Retirement Benefits ("OPEB") associated with the management services provided by NiSource Corporate Services Company ("NCSC"). The costs are being incurred by Columbia as a result of a change by NCSC from billing its OPEB costs on a claims paid basis to an accrual method and funding of a VEBA trust for the difference between accrued amounts above amounts paid. Columbia will seek to recover such costs in its next general base rate proceeding, pursuant to Section 1308(d) of the Public Utility Code, 66 Pa. C.S. § 1308(d).

Columbia is not requesting that the Commission decide the ratemaking treatment for such costs through this Petition. Columbia seeks only Commission authority to defer these costs for accounting and reporting purposes until Columbia can present a claim for recovery of these costs in its next base rate proceeding.

In support of this request, Columbia states as follows:

II. BACKGROUND

1. Columbia is a corporation organized and existing under the laws of the Commonwealth of Pennsylvania. Columbia is engaged in the business of selling and distributing natural gas to retail customers within the Commonwealth, and is therefore a "public utility" within the meaning of Section 102 of the Public Utility Code, 66 Pa. C.S. § 102, subject to the regulatory jurisdiction of the Commission. Columbia provides natural gas service to approximately 414,000 customers in 26 counties of Pennsylvania, pursuant to certificates of public convenience granted by the Commission.

2. NCSC is a subsidiary of NiSource Inc. ("NiSource") and an affiliate of Columbia within the NiSource corporate organization. NCSC provides a range of services to the individual operating companies within NiSource, including Columbia. Specifically, NCSC provides corporate, administrative and technical support services and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided directly by NCSC and by third party vendors. Each affiliate is billed on a monthly basis for its proportional share of the costs incurred in that respective month. NCSC renders all services performed under a Service Agreement with its affiliates at cost, including overheads and charges for interest where appropriate. The Service Agreement between NCSC and Columbia was filed with the Commission and approved by Order dated December 15, 2005 at Docket No. G-00051117.

3. The complete name and address of the Petitioner are:

Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, Pennsylvania 15317

4. The names, addresses and telephone numbers of Columbia's attorneys for purposes of this filing are as follows:

Michael W. Hassell (ID # 34851)
Andrew S. Tubbs (ID # 80310)
Post & Schell, P.C.
17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
Phone: 717-731-1970
Fax: 717-731-1985
E-mail: mhassell@postschell.com
E-mail: atubbs@postschell.com

Theodore J. Gallagher (ID # 90842)
Kimberly S. Cuccia (ID # 308216)
NiSource Corporate Services Company
Energy Distribution Group Legal
121 Champion Way, Suite 100
Canonsburg, PA 15317

5. In December 1990, the Financial Accounting Standards Board ("FASB") issued SFAS 106 (codified in ASC 715), which required employers to adopt, for financial accounting purposes, an accrual method of accounting for the costs to provide benefits other than pension to retired employees ("other post-retirement benefits" or "OPEBs").

6. The accounting procedures for OPEB costs have changed over the years. Prior to implementing SFAS No. 106, employers were permitted to account for the recognized costs of OPEBs as claims were paid or on a "pay-as-you-go" method. As a result, a liability for future benefit obligations was not required and expense was recognized when the retiree benefits were paid. However, under SFAS 106, FASB determined that it was appropriate to record post-retirement benefits on the accrual basis and recognize a liability as employees actually earned the benefits.

7. To address the numerous filings made by Pennsylvania jurisdictional electric and gas utilities associated with implementing SFAS No. 106, the Commission implemented a statement of policy that became effective on June 19, 1993. The Commission's Policy Statement

set forth standards governing petitions requesting deferral of SFAS No. 106 incremental costs including, requiring that a utility present sufficient documentation to support its SFAS 106 cost estimates and sufficient cost containment measures and the use of a trust for accrual amounts in excess of claim amount. *Implementation of Statement of Financial Accounting Standards for Rule No. 106 (SFAS 106)—statement of policy.*, 52 Pa. Code §69.351(b).

8. Like many other companies, NiSource provides health care and life insurance benefits for certain retired employees, including those of NCSC. OPEB costs are comprised of retiree medical expense and retiree group life insurance.

9. NCSC and Columbia adopted SFAS No. 106 for financial reporting purposes effective January 1, 1991. Thereafter, both companies recorded a liability reflecting the expected future obligation for OPEB costs and recognized the future recovery of such costs as a regulatory asset. In 1993, Columbia requested and received Commission approval to defer and recover in future rates prudently incurred incremental costs of OPEBs that Columbia was required to begin recognizing for financial reporting purposes. *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket No. P-00930727 (Opinion and Order entered February 2, 1994). Columbia continued to defer the difference between claims paid and the SFAS 106 accrual until Columbia's 1994 rate case at Docket No. R-00943001, wherein the Commission addressed the appropriate rate treatment for Columbia's OPEB costs.

10. As a result of the Commission's 1994 order, Columbia recognized in its cost of service the accrual-based Columbia OPEB expense level and began amortizing the regulatory asset costs recognized on its books. In addition, in accordance with the Commission's statement of policy, Columbia began funding an OPEB trust to set aside the dollars collected for future

retiree costs. In every rate case since, Columbia has reflected its OPEB costs for ratemaking purposes using the accrual method.

11. As noted above, as of January 1, 1991, NCSC adopted SFAS No. 106 and recognized a liability for financial reporting purposes. However, for purposes of billing affiliates for provided services, NCSC continued to charge OPEB costs related to its employees as claims were paid. Therefore, the costs included in the Columbia management services charges in Columbia's 1994 base rate proceeding and all subsequent rate cases have reflected NCSC OPEB costs on a cash basis. As a result, NCSC continued to defer the difference between OPEB claims paid and the SFAS 106 accrual expense. As of December 31, 2010, NCSC had deferred \$9,883,242 in total OPEB accrual costs in excess of claims paid.

12. Through a recent review of GAAP and FERC guidance as well as a consultation with its auditors, in June 2011 NCSC determined that it can no longer continue to carry the deferral of the difference between OPEB claims paid and SFAS 106 accruals as an asset on its balance sheet. Therefore, NCSC has begun to record and bill to its affiliates retiree medical and life costs calculated on an SFAS No. 106 accrual basis beginning in 2011. In addition, the entire NCSC regulatory asset balance as of December 31, 2010 was billed by NCSC to the subsidiaries, including Columbia, in June 2011.

13. In addition to changing the OPEB expense recognition procedure from cash basis to accrual, NCSC funded an OPEB trust for accrual related costs collected in advance of the need to pay retiree costs in a manner similar to Columbia's procedures. The \$9,883,242 billed to all affected affiliates in June 2011 was funded in a trust in September 2011.¹ The funding of the

¹ NCSC allocated the regulatory asset to the NiSource affiliates, including Columbia, using a monthly overhead rate (calculated based on the direct and allocated labor billed to each affiliate divided by the total direct and allocated labor billed to all affiliates).

annual NCSC OPEB accrual amounts to the trust will begin in January 2012. The earnings from the trust will be used to help pay future NCSC OPEB claims.

14. Attached as Appendix "A" are Columbia's journal entries that show that Columbia was billed a total of \$970,215.78 for its allocated share of the December 31, 2010 NCSC regulatory asset. Further, the journal entries reflect that Columbia capitalized \$67,085.14 of this billing to reflect the fact that had these costs been billed to Columbia over time, a portion would have been allocated to capital projects. The remaining \$903,130.64 was recorded as a regulatory asset pending a Commission order in this proceeding.

III. THE TRANSITION FROM CASH BASIS TO ACCRUAL BILLING BY NCSC IS A ONE TIME, NON RECURRING COST THAT COLUMBIA SHOULD HAVE THE RIGHT TO SEEK TO RECOVER IN A FUTURE RATE PROCEEDING

15. Columbia's current base rates, as well as base rates in prior cases, included a representative level of NCSC OPEB claims paid. The deferral and recovery of the Columbia portion of the deferred NCSC OPEB-related asset balance due to the NCSC billing change from cash basis to accrual is appropriate because it represents costs that Columbia would normally be entitled to recover in future rate cases if NCSC had continued to bill on a cash basis.

16. In addition, these costs have not previously been charged to Columbia through the NCSC management fee. The existence of the NCSC regulatory asset demonstrates that Columbia has not previously been charged these costs and included them in rate activities, and therefore, Columbia should appropriately be able to recover the NCSC OPEB-related asset in a future rate proceeding.

17. The aforementioned costs generated by the change in expense recognition at NCSC are reasonable and necessary business costs incurred by Columbia in compliance with GAAP and FERC guidance that may result in a significant and unavoidable negative impact on Columbia's earnings. As a result, Columbia requests the authority to defer \$903,103.64 for the

one-time charge generated by the NCSC accounting procedure change. Consistent with prior Commission decisions, the ultimate recovery treatment will be determined in a subsequent Columbia base rate case proceeding in a manner deemed appropriate by the Commission. *Pa. P.U.C. v. Pennsylvania Power & Light Co.*, Docket No. P-00920635 (May 6, 1993) (Approved deferral of transition costs under Financial Accounting Standards Board Statement of Financial Accounting Standards No. 106 ("SFAS 106")).²

IV. COLUMBIA'S PETITION SATISFIES THE COMMISSION'S POLICY STATEMENT REGARDING RECOVERY OF SFAS NO. 106 ACCRUALS

18. Columbia has satisfied the requirements of the Commission's SFAS No. 106 Policy Statement, and therefore should be granted permission to defer NCSC's allocated SFAS No. 106 costs:

- NCSC administers Columbia's basic post retirement nonpension benefit program that consists of two major benefit plans, medical and life insurance. This program provides for uniform benefit plans that are administered on a nondiscretionary basis for all NCSC's subsidiary companies, including Columbia.
- The NiSource system actively investigates ways in which to contain and/or control its OPEB costs. These efforts have been detailed in prior Columbia proceedings, and include: implemented a fixed company dollar subsidy for retiree medical pre and post age 65 for retirements after January 2004 thus the retiree absorbs any medical inflation each year after retirement; implementing High Deductible Plans for pre-65 retirees in 2006; eliminating high cost HMOs from pre-65 retiree selection; exempting new hires beginning January 1, 2010 and after are no longer eligible for post retirement medical or life insurance; and Retiree Rx drug plans have built in generic incentives.
- NCSC funded a VEBA trust with the deferred OPEB costs billed to affected affiliates, and plans to continue to fund a trust for OPEB accrual amounts.

² The Office of Consumer Advocate ("OCA") appealed this decision, and the Commonwealth Court reversed the Commission with regard to the approval of recovery of costs outside of a rate proceeding. The Commonwealth Court did not reverse the decision with regard to the deferral of the SFAS 106 expenses. *Popowsky v. Pa. P.U.C.*, 164 Pa. Cmwlth. 338, 348, 642 A.2d 648, 653 (1994).

V. **THE COMMISSION'S PERMISSION TO ALLOW COLUMBIA TO ESTABLISH A REGULATORY ASSET WILL NOT IMPAIR OTHER PARTIES' RIGHTS**

19. It must be emphasized that Columbia is not requesting the Commission to decide, at this time, whether deferred costs resulting from the allocation of NCSC costs to Columbia are recoverable through rates charged to customers. Instead, Columbia is simply requesting permission to defer these costs on its books of account pending such determination in its next general base rate proceeding. Although Columbia believes that such costs should be recoverable from customers, that issue will be addressed in a general base rate proceeding pursuant to Section 1308(d) of the Public Utility Code, 66 Pa. C.S. § 1308(d).

20. Columbia is not seeking any determination at this time as to the reasonableness or prudence of any specific costs. Therefore, no party will be prejudiced by the granting of this Petition. Columbia understands that other parties will be permitted to challenge Columbia's recovery of deferred costs caused by the allocation of NCSC costs in its next general base rate proceeding, except that those parties cannot contend that Columbia should have filed a petition to defer those costs on its books of account. Columbia will address the reasonableness and prudence of specific costs in the future in an appropriate proceeding before the Commission. Columbia proposes that the length of the amortization of the NCSC OPEB costs also be determined by the Commission in the same general rate increase proceeding. Should the Commission believe that amortization of the NCSC OPEB costs should begin immediately, Columbia proposes an amortization period of ten (10) years. However, Columbia requests that the Commission clarify that any immediate amortization of these costs shall not affect Columbia's right to seek full recovery of these costs. *Petition of West Penn Power Company for Authority to Defer for Regulatory Accounting and Reporting Purposes Certain Losses from*

Extraordinary Storm Damage, Docket No. P-2010-2216111, reconsideration denied, clarification granted (Order entered July 18, 2011).

21. Based upon the foregoing, Columbia respectfully requests that it be permitted to defer as a regulatory asset the one time expense of \$903,130.64 associated with its allocated share of NCSC's OPEB regulatory asset resulting from the transition from cash basis to accrual.

VI. CONCLUSION

WHEREFORE, for all the foregoing reasons, Columbia Gas of Pennsylvania, Inc. respectfully requests that the Pennsylvania Public Utility Commission authorize Columbia Gas of Pennsylvania, Inc. to defer, for accounting and financial reporting purposes, the one-time expense of \$903,130.64 associated with the change its allocated share of NiSource Corporate Services Company's Other Post-Retirement Benefits regulatory asset resulting from the transition from cash basis to accrual.

Respectfully submitted,

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Attorneys for Columbia Gas of Pennsylvania, Inc.

Appendix “A”

10/10/11

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPEB ADJUSTMENT
FOR THE YEAR 2011

PAGE 1

CO --	Gen ---	Aux ---	Cost Ele -----	Activity -----	Journal -----	Mo --	Desc -----	\$ Amount -----
37	182	3501	8010	12473	I/C-12-101	06	057201563790114270 OPEB ADJUSTMENT	970,215.78
37	234	9912		14070	I/C-12-101	06	ACCOUNTS PAYABLE TO NCSC	970,215.78-
								.00

Run Date: 7/07/11
Run Time: 9.24.49

Columbia Gas of Pennsylvania, Inc.
June, 2011

Journal Id:
SPL-99-001

Journal Seq:
00024

Effdt:
06/30/11

Posting Date:
90/19/51

----- Journal Title -----

SPL-99-001: CORRECTIONS AND ADJUSTMENTS - GENERAL ACCOUNTING

----- Journal Description -----

----- Account Summary -----				
Gen	Debits (\$)	Credits (\$)	Net (\$)	Statistics
107	67,085.14	0.00	67,085.14	0.00
182	0.00	67,085.14-	67,085.14-	0.00
Totals	67,085.14	67,085.14-	0.00	
Net Income Total			0.00	

EXTRACT : CAGENACCTU
APPLICATION: CAX
REPORT NAME: CAGENACCTU
CYCLE : BGENACCT
COTRAC ID : CAGENACCTU

COLUMBIA GAS OF PENNSYLVANIA, INC.
CURRENT PERIOD LOCKED JOURNALS - 06/30/11
JOURNAL PSEUDO-CODE (USP): FILES
JOURNAL ID --> SPL-99-001 JOURNAL SEQ. --> 24
JOURNAL DESCRIPTION --> CORRECTIONS AND ADJU

PAGE
RUN DATE: 87/0:
RUN TIME: 08:42

LINE #	CO	GEN	AUX	CE	PROJ	ACTV	FACIL	NOC	TOC	LB	PT	PT	PSEUDO-CODE	DOLLAR AMOUNT	STATISTICS	JOURNAL ENTRY DESCRIPTION	STA
18	37	187		8099			10880		2589					67,085.14	.00	OPER ADJUSTMENT	
GEN 107 TOTALS ----->														67,085.14	.00		
20	37	182	5501	8099			12473							67,085.14	.00	OPER ADJUSTMENT	
GEN 182 TOTALS ----->														67,085.14	.00		
TOTAL DEBITS: JOURNAL SPL-99-001 -->														67,085.14	.00	JOURNAL SEQUENCE --> 24	
TOTAL CREDITS: JOURNAL SPL-99-001 -->														67,085.14	.00	JOURNAL SEQUENCE --> 24	

THIS JOURNAL IS NOT APPROVED THIS JOURNAL IS NOT APPROVED THIS JOURNAL IS NOT APPROVED

VERIFICATION

I, Mark R. Kempic, hereby state that the facts above set forth are true and correct (or are true and correct to the best of my knowledge, information and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements made herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: 11/29/11

Mark R. Kempic
Mark R. Kempic
Director, Rates & Regulatory Policy
Columbia Gas of Pennsylvania, Inc.

**PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265**

Public Meeting held May 24, 2012

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
Wayne E. Gardner
James H. Cawley
Pamela A. Witmer

Petition of Columbia Gas of Pennsylvania,
Inc. for Authority to Defer, For Accounting
Purposes, Certain Costs Associated With A
Regulatory Asset Related to Other Post-
Retirement Benefits Provided By NiSource
Corporate Service Company

Docket No. P-2011-2275383

OPINION AND ORDER

BY THE COMMISSION:

On November 29, 2011, Columbia Gas of Pennsylvania, Inc. (Columbia or Company) filed a Petition for authority to defer, for accounting purposes, certain costs associated with a regulatory asset related to other post-retirement benefits provided by NiSource Corporate Service Company (Petition). Columbia is requesting that we issue an order under Section 1701 of the Public Utility Code, 66 Pa. C.S. § 1701 (Mandatory system of accounts), granting it the authority to defer, for accounting purposes, expenses attributable to a change by its affiliate, NiSource Corporate Services Company (NCSC), with regard to management services NCSC provides to Columbia. Petition, p. 1. Columbia is incurring these expenses as the result of a change by NCSC from billing its OPEB costs on a claims paid basis to an accrual method and funding of a Voluntary

Employees Beneficiary Association (VEBA)¹ trust for the difference between accrued amounts above amounts paid. *Id.* Columbia does not seek recovery of the incurred expenses at this time, but asks us to approve a deferral of the expenses until such time as it files its next general base rate proceeding pursuant to section 1308(d) of the Public Utility Code (66 Pa. C.S. § 1308(d)). *Id.*

The Petition

Other Post-Retirement Benefits are benefits that an employee will begin to receive at the start of retirement other than pension benefits paid to the retired employee. Other post-employment benefits that a retiree can be compensated for include life insurance premiums, healthcare premiums and deferred-compensation arrangements. In the past, employers could account for the recognized costs of OPEBs on a pay-as-you-go basis. In short, the expense was not recognized until the retiree benefits were paid.

In 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards Rule No. 106 (SFAS No. 106) in which it determined that it was proper for employers to recognize liabilities as employees actually earned the benefits and to record OPEBs on the accrual basis. In response, we issued our *Implementation of Statement of Financial Accounting Standards for Rule No. 106 (SFAS 106) -- statement of policy* at 52 Pa. Code § 69.351 which governed petitions requesting deferral of SFAS No. 106 incremental costs.

NCSC and Columbia each adopted SFAS No. 106 for financial reporting purposes

¹ A VEBA is a tax-exempt entity which usually provides its members and their dependents and beneficiaries with paid life insurance, health insurance, and accident insurance. The VEBA can be established by any employer for employees even if they already have a retirement plan.

in 1991.² Petition, p. 4. The Commission addressed the appropriate treatment for Columbia's OPEB costs in rates in its decision regarding the Company's 1994 base rate case. *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket R-00943001, order entered July 22, 1994. In response to this order, Columbia recognized the accrual-based OPEB expense level in its cost of service and began amortizing the regulatory assets recognized on its books. Petition, pp. 4-5. Also, the Company began funding an OPEB trust to set aside the amounts collected for future retiree costs, consistent with the Commission's statement of policy. *Id.*

Although Columbia used the accrual method of accounting for its OPEBs, Columbia Energy Service Corp. continued to account for its OPEBs on a pay-as-you-go method and bill Columbia and the affiliated operating companies accordingly. As noted earlier, NiSource and the Columbia system merged in 2000. In 2004 NCSC took over the service role which had previously been filed by Columbia Energy Service Corp. However, NCSC continued to bill for OPEBs related to its own employees on a pay-as-you-go basis.

Following a review of Generally Accepted Accounting Principles (GAAP), decisions of the Federal Energy Regulatory Commission (FERC) and in consultation with its own auditors, NCSC determined that it could no longer continue to carry the deferral of the difference between OPEB claims paid and SFAS No. 106 accruals as an asset on its balance sheet. Petition, p. 5. In 2011, NCSC began to record and bill its affiliates retiree medical and other costs calculated on an accrual basis. *Id.* Moreover, in June 2011, NCSC billed its affiliates the entire NCSC regulatory asset balance as of December 31, 2010. NCSC also funded an OPEB trust for accrual related costs collected in advance of actual payment of retiree costs much the way Columbia did with its own retiree costs.

² It should be noted that Columbia Gas of Pennsylvania was not part of NiSource at that time. NiSource and the Columbia Energy Group, which included Columbia Gas of Pennsylvania, merged in 2000.

Id.

NCSC billed nearly \$9,883,242 to all affected affiliates in June 2011. This amount was funded in a trust in September 2011. *Id.* The funding of the annual NCSC OPEB accrual amounts to the trust were to begin in January 2012, the earnings of which are to be used to help pay future NCSC OPEB claims. Petition, pp. 5-6. Columbia was billed approximately \$970,216 for its allocated share of the December 31, 2010 NCSC regulatory asset. Petition, p. 6 and Appendix A. Columbia capitalized approximately \$67,000 of this amount to reflect that had these costs been billed to Columbia over time, a portion would have been allocated to capital projects. Petition, p. 6. The remaining \$903,130.64 was recorded as a regulatory asset pending our decision in this proceeding. *Id.*

Columbia maintains that the change from a cash basis to accrual billing is a one-time, non-recurring cost from NCSC which qualifies for treatment on a deferred ratemaking basis. Petition, pp. 6-7. The Company states that its current and past base rates have included representative levels of NCSC OPEB claims paid and that deferral of the NCSC OPEB-related asset balance due to the billing change is appropriate because, had there been no change in accounting, the Company would have been entitled to recovery in future rate cases. *Id.* Columbia describes the costs in question as “reasonable and necessary business costs” which have been incurred in compliance with GAAP and FERC guidance.

The Office of Consumer Advocate (OCA) filed an Answer December 19, 2011, arguing that if the Commission decides to grant the petition, it should impose certain conditions. OCA Answer, p. 2. It states we should direct that, if deferred treatment for accounting purposes is granted, it should be clear that this does not guarantee future rate recovery. *Id.* Columbia should be directed to make its claim for recovery at its first

available opportunity. *Id.* OCA further recommends that any order we may issue here will not limit the ability of a party to challenge recovery of these costs when Columbia files its claim. *Id.*

Discussion

The sole issue for consideration before us today is whether Columbia should be authorized to defer certain expenses associated with NCSC's change from billing its OPEB-related expenses on a cash basis to an accrual basis. The ratemaking treatment of these expenses, if any, shall be addressed in a future ratemaking proceeding. That future base rate proceeding is the proper forum for the resolution of any objections to the Petition asserted by OCA or any other party.

Today's decision is not a directive that Columbia must defer these expenses, nor are we making any determination as to the veracity of the Company's claim or the appropriate treatment for recovery of any allowable costs in a future period. Our decision today involves only our authorization for the Company to defer certain expenses for accounting purposes.

The issue before us is simply whether we should authorize Columbia to defer for financial accounting purposes expenses which may be approximately \$900,000. Whether the expenses are extraordinary and whether the expenses were reasonably and prudently incurred are issues we are not called upon to decide here. Rather, the standard which a utility must meet when seeking Commission authorization for deferral accounting is whether, based on Commission precedent, the expense item appears to be within the scope of the type of items that the Commission has allowed as an exception to the general rule against retroactive recovery of past expenses.

We find that Columbia has established a *prima facie* case pursuant to the above standard. However, we are not making any factual findings in this Order. A petition seeking authorization for deferral accounting is not intended to create a factual record. As such this determination will be of no weight in such future proceeding. The burden of proof remains with Columbia. 66 Pa. C.S. § 315(a). While we grant Columbia's Petition subject to the conditions discussed herein, we will direct the Company to immediately begin expensing the deferred amounts on a reasonable amortization schedule;
THEREFORE,

IT IS ORDERED:

1. That Columbia's Petition for authority to defer for accounting and financial reporting purposes certain expenses related to the change in accounting methodology and subsequent billing of OPEB-related costs by NiSource Corporate Services Company and to amortize such expenses is granted subject to the following conditions:

- a. Authorization for deferred accounting treatment is not an assurance that future rate recovery is probable;
- b. Columbia shall claim the deferred expenses at its first available opportunity;
- c. Upon entry of this Order, Columbia shall begin expensing the deferred amounts on a reasonable amortization schedule;
- d. This Order does not preclude Columbia from seeking recovery of the total amount of its deferred expenses;
- e. This authorization is limited to Columbia's actual billed OPEB-related expenses by NCSC and does not extend to those costs which are more properly capitalized; and

f. In the event Columbia should enter into a "black box" settlement with other parties in the base rate proceeding in which it seeks to recover these costs, it shall provide sufficient information with respect to this expense item to enable the Commission to make a determination as to the annual amortization of these deferred costs in the level of rates agreed to in the settlement.

2. That nothing in this opinion and order limits the ability of any party to a future rate case to seek or oppose rate recovery of all or any part of the costs deferred pursuant to this authorization.

3. That a copy of this order be served upon Columbia, the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate and the Office of Small Business Advocate.

4. That this proceeding be marked closed.

BY THE COMMISSION,



Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: May 24, 2012

ORDER ENTERED: May 24, 2012

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

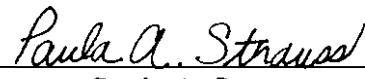
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Paula A. Strauss, being Director of Regulatory Strategy and Support of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 15 and 115-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. PAS-1 through PAS-4 and PAS-1R through PAS-4R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Paula A. Strauss

2-13-13
Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
PAULA A. STRAUSS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

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1 **1. Introduction**

2 Q. Please state your name and business address.

3 A. My name is Paula A. Strauss. My business address is 200 Civic Center
4 Drive, Columbus, Ohio 43215.

5 Q. By whom are you employed and in what capacity?

6 A. I am employed by NiSource Corporate Services Company ("NCSC"), a
7 management and services subsidiary of NiSource Inc. ("NiSource"). My
8 current title is Director of Regulatory Strategy and Support.

9 Q. Please briefly describe your professional experience.

10 A. From January 1992 through November 1996, I was employed by Niagara
11 Mohawk Power Corporation ("Niagara Mohawk"). While at Niagara
12 Mohawk, I worked as a Planner in the Corporate Strategic Planning
13 Department and a Pricing Analyst in the Marketing Department. I began
14 working for Northern Utilities Inc. ("Northern") and Bay State Gas
15 Company ("Bay State") in December 1996 as a Senior Pricing Analyst. I
16 was promoted to Manager of Pricing and Revenue Development in August
17 1999. As a result of Northern's merger and reorganization that resulted in
18 its acquisition by NiSource, I accepted a position in Columbus Ohio as a
19 Lead Regulatory Analyst in January 2002. I was promoted to Manager of
20 Regulatory Accounting in May 2006. In early 2010, I joined Financial
21 Planning as a Manager. I was promoted to my current position, Director
22 of Regulatory Strategy and Support in October 2010.

23 Q. Please describe your educational background.

1 A. I received a Bachelor of Arts Degree in Economics in 1990 from the State
2 University of New York at Oswego. In 1991, I graduated from the State
3 University of New York at Binghamton with a Masters of Science Degree in
4 Economics.

5 Q. What are your responsibilities in your current position?

6 A. As Director of Regulatory Strategy and Support, my principal
7 responsibilities include all regulatory activities for Columbia Gas of
8 Pennsylvania, Inc. ("Columbia" or the "Company"), Columbia Gas of
9 Maryland and Columbia Gas of Massachusetts. I oversee and prepare
10 regulatory compliance filings, such as gas cost adjustment filings and
11 provide base rate case support.

12 Q. Have you previously testified before this or any other regulatory agency?

13 A. Yes. I provided written testimony concerning rate design for Columbia
14 Gas of Pennsylvania, Inc. in Dockets R-2008-2011621 and R-2009-
15 2149262. In New Hampshire, I filed written testimony as support for
16 Northern's Petitions for Approval of Special Firm Transportation
17 Agreements with Simplex Technologies, Inc., DG 99-109, National
18 Gypsum Company, DG 99-123, and Foss Manufacturing Company, Inc.,
19 DG 99-171. Additionally, I served as Northern's rate design witness in DG
20 00-046. In Maine Docket 97-393, I served as Northern's rate design
21 witness. I filed written testimony and testified before the Maine Public
22 Utilities Commission. I also served as Northern's witness in Maine Docket
23 No. 2000-848, Request for Approval of a Firm Gas Transportation

1 Agreement with Interstate Brands Corporation. In Massachusetts, I
2 testified in Docket D.T.E. 99-34, which involved the merits of a demand-
3 based Extra Large Volume Rate Class.

4
5 **2. Purpose and Organization**

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

7 A. The primary purpose of my testimony is to present and support
8 Columbia's rate design, proposed rates and bill impacts.

9 Q. What test year will you be addressing in your testimony?

10 A. I will be addressing the Fully Forecasted Rate Year, which is the twelve-
11 month period ending June 30, 2014.

12 Q. How is your testimony organized?

13 A. This testimony includes the following sections: (1) Introduction; (2)
14 Purpose and Organization; (3) Residential Rate Design Options; (4) Rate
15 Design and Revenue Allocation (5) Rate Design Option 1 - Revenue
16 Normalization Adjustment (RNA); (6) Rate Design Option 2 - Weather
17 Normalization Adjustment (WNA); (7) Rate Design Option 3 - Levelized
18 Distribution Charge (LDC); (8) Proposed Commercial and Industrial Base
19 Rates; (9) Gas Procurement Charge (GPC) and (10) Revenue Proof and Bill
20 Impacts.

1 Q. What Exhibits are you supporting?

2 A. The following Exhibits are presented with this testimony: Exhibit No. 13,
3 Schedule 1 (pages 1 and 2), Exhibit No. 103, Schedule 8 and Exhibit No.
4 111, Schedules 5 and 6 (pages 1 through 9 on each schedule).

5 Q. Please provide a summary of the base rates being proposed by the
6 Company.

7 A. Please refer to Exhibit No. 103, Schedule 8. Column 7 shows the proposed
8 base rates.

9

10 **3. Residential Rate Design Options**

11 Q. Describe Columbia's current residential rate structure.

12 A. The Company's current rate structure includes a customer charge of
13 \$18.73 and a usage based charge of \$2.6708 per Dth that is applied to all
14 consumption in excess of 2.1 Dth in any given month. This rate structure
15 was proposed by the Bureau of Investigation and Enforcement ("BI&E")
16 and approved by the Commission in Docket No. 2010-2215623.

17 Q. Is the Company presenting residential rate design options in this
18 proceeding?

19 A. Yes. The Company is presenting three rate design options for residential
20 customers. The rate design alternatives are described in this testimony
21 and the Company's primary residential rate design option is shown on
22 Exhibit No. 103, Schedule 8 and in the proposed tariff, which is being

1 sponsored by Company witness Bardes-Hasson (Columbia Statement No.
2 16).

3 Q. Why is the Company proposing rate design options for residential
4 customers?

5 A. The Commission's Order in Columbia's prior rate case at Docket No. 2010-
6 2215623 noted that the Company and the Parties provided limited viable
7 alternatives concerning residential rate design. Page 52 of the
8 Commission's Opinion and Order states the following:

9 Before us were two divergent positions, neither of which
10 was perceived as an optimal solution. Columbia proposed
11 to recover all distribution costs in fixed customer charges.
12 Such a proposal would have achieved Columbia's goals of
13 stable revenues, but at the expense of consumer interests in
14 benefiting from energy efficiency investments. On the other
15 hand, OCA proposed to maintain the status quo – placing
16 Columbia's business at greater risk of collecting their
17 approved cost of service, but benefiting consumer's
18 interests in better controlling their cost of distribution
19 service. The only alternative was offered by BI&E, who
20 rendered a proposal to stabilize revenues somewhat by
21 marginally increasing the customer charge from \$12.25 per
22 month to \$ 18.73 per month. This increase, based on a 2
23 Mcf per month minimum charge, offers the only viable
24 alternative in this proceeding to better balance the interests
25 of consumers and the utility.
26

27 Given the lack of alternatives presented for our
28 consideration in this proceeding, the decision made today is
29 applicable to this proceeding and should not be considered
30 as precedential. Going forward, we encourage parties to
31 present viable alternate rate mechanisms for our
32 consideration that may more optimally balance the needs of
33 consumers and utilities in delivering reliable natural gas
34 safely, and at the lowest, long term cost.
35

1 Q. Please present the Company's rate design options for residential
2 customers.

3 A. Columbia is proposing the following three rate design options:

4 o Rate Design Option 1 includes a system charge, a per therm
5 distribution rate and a Revenue Normalization Adjustment (RNA). No
6 usage allowance is included in the system charge.¹ This residential rate
7 design option is presented in the Company's proposed tariff.

8 o Rate Design Option 2 includes a system charge, a per therm
9 distribution rate and a Weather Normalization Adjustment (WNA). No
10 usage allowance is included in the system charge.

11 o Rate Design Option 3 includes a system charge and no per therm
12 distribution rate. The Company's complete revenue requirement is
13 included in the system charge.

14 Each of these rate design options is described in more detail in later
15 sections of this testimony.

16 Q. Which rate design option is preferred by the Company?

17 A. The Company's primary rate design proposal is option 1, including the
18 RNA mechanism.

19 Q. Is the Company proposing a rate design option which includes a usage
20 allowance in the system charge?

¹ As discussed in the testimony of Company witness Bardes-Hasson, the Company is proposing to change its billing terminology from "Customer Charge" to "System Charge."

1 A. Yes. Option 3 includes all usage in the system charge. Since options 1 and
2 2, include RNA and WNA, respectively, there is no usage allowance in the
3 system charge.

4
5 **4. Rate Design and Revenue Allocation**

6 Q. What is the Company's proposed revenue increase?

7 A. The filed rates will produce an increase in annual revenues of
8 approximately \$77.3 million. Please refer to the testimony and schedules
9 of Company witness Gore (Columbia Statement No. 4) for details
10 concerning the Company's revenue requirement.

11 Q. Please describe the rate design principles that the Company considered
12 when developing the proposed rates.

13 A. The principles that were used to guide the development of the Company's
14 rate design include: efficiency, simplicity, continuity, fairness, and
15 corporate earnings stability. An efficient rate design provides an accurate
16 basis for consumers' decisions and allows the Company to recover the cost
17 of providing service. A simple rate structure is understood by customers.
18 The goal of rate continuity implies that customers will have an adequate
19 opportunity to adjust their consumption patterns, as needed. A fair rate
20 design considers the results of the allocated cost of service study in
21 determining customer classes' total revenue responsibility. Finally,
22 corporate earnings stability means that the Company's earnings resulting
23 from its rates should not vary significantly over the period of a few years.

1 Company witness Kempic (Columbia Statement No. 1) testifies about the
2 policy need for a rate design that provides more certainty for recovery of
3 the residential revenue requirement and some of the rate designs adopted
4 in other jurisdictions.

5 Q. Please describe how the revenue increase was allocated among rate
6 schedules.

7 A. The initial allocation of the revenue requirement to the rate schedules was
8 performed using the Fully Forecasted Rate Year non-gas revenues for each
9 customer group being allocated a portion of the increase. The revenues
10 are shown on Exhibit No. 103, Schedule 1 and supported by Company
11 witness Bell (Columbia Statement No. 3). In order to develop allocation
12 percentages, rate schedules were assigned to groups. For example, all
13 residential rate schedules, including RSS, CAP, RDGSS, RDS (Choice), and
14 RDGDS (Choice) were grouped together. Similarly, commercial and
15 industrial customers using less than 64,400 therms annually were
16 combined (SGSS, SCD and SGDS). The other customer groups include
17 LGSS (commercial and industrial sales customers using more than 64,400
18 therms annually), SDS (commercial and industrial distribution customers
19 using between 64,400 and 540,000 therms annually), LDS (Large
20 Distribution Service), and Mainline Service.

21 Q. Please explain the next steps in the allocation of revenue requirement.

22 A. After the rate schedules were assigned to groups, Fully Forecasted Rate
23 Year base revenues at present rates for these groups, excluding revenues

1 resulting from Rider USP, were summed. These revenues were used to
2 develop allocation percentages and the initial assignment of revenue
3 responsibility at proposed rates for each customer group being allocated a
4 portion of the rate increase.

5 Q. Please describe the treatment of Rider USP charges in your revenue
6 allocation.

7 A. I excluded Rider USP revenues from the allocation process because these
8 costs are recovered through a separate reconciled charge.

9 Q. What was the next step in the revenue allocation process?

10 A. The resulting rate increases were reviewed for reasonableness and
11 adjustments were made to the initial allocation.

12 Q. Please state the basis for evaluating the reasonableness of the Company's
13 proposed revenue allocation.

14 A. The Class Cost of Service Studies ("CCOS") developed by Company witness
15 Skirtich (Columbia Statement No. 9) were used to evaluate the
16 reasonableness of the Company's proposed revenue allocation. The results
17 of the Customer / Demand Study and Peak and Average Study provide a
18 range of costs to serve each customer class. The Average Study shows a
19 combination of the two studies and is the study that the Company most
20 relied upon to provide guidance for the revenue allocation and rate design
21 process. Please refer to witness Skirtich's testimony for the detailed
22 allocated cost of service methods employed by the Company.

1 Q. Why did the Company rely primarily upon the results of the Average
2 Study?

3 A. As Mr. Skirtich explains, in a number of prior rate cases, Columbia has
4 relied upon the results of both a Customer/Demand Study and a
5 Peak/Average Study to provide a range of reasonableness in assessing
6 class cost responsibility. The Company has presented both of those
7 studies in this proceeding. Columbia has also developed an actual average
8 of the two studies to provide a more clear guide for revenue allocation, in
9 the event it is determined that the results of a single study should be used.

10 Q. Please provide the base revenue requirements by rate schedule proposed
11 in this case.

12 A. The base revenue requirements by rate schedule are shown on Exhibit No.
13 103, Schedule 8, Column 6. These revenue requirements result from the
14 allocation process described in this section of testimony.

15 Q. Please provide a summary of the revenue requirement increases shown in
16 Exhibit No. 103, Schedule 8, Column 5.

17

- 1 A. The table below provides a summary of the revenue requirement increases
2 proposed:

Columbia's Revenue Allocation Proposal

<u>RS/RDS</u>	<u>SGS/SGDS/SCD</u>	<u>SDS</u>	<u>LGS</u>	<u>LDS*</u>	<u>MLD*</u>	<u>Total</u>
\$61,779,186	\$14,356,847	\$581,688	\$582,089	\$11,011	\$279	\$77,311,100
79.91%	18.57%	0.75%	0.75%	0.01%	0.00%	100.00%

* Increase attributed to STAS

- 3
4 Q. Why were Mainline Service customers not assigned a revenue increase
5 through the allocation process?

- 6 A. Please refer to the testimony of witness Skirtich. Exhibit JES-1 displays
7 returns by customer group. As shown on this exhibit, Mainline Service
8 customers are sufficiently covering their allocated share of the revenue
9 requirement at present rates under the Average Study (and in fact under
10 all three studies).

- 11 Q. Will rates for Mainline Service customers change?

- 12 A. The system service charges and consumption rates for Mainline Service
13 will not change. However, as part of the rate case, Columbia sets the
14 current State Tax Adjustment Surcharge (STAS) rate to 0%. This change
15 in STAS causes annual revenues for the Mainline Service customers to
16 increase by \$279. Also since one of the Mainline Service customers is a
17 sales customer, the new Gas Procurement Charge (GPC) will be applied to

1 their volumes. This will cause an annual rate increase of \$879. Details
2 related to the GPC are provided later in this testimony.

3 Q. Why were LDS customers not assigned a revenue increase?

4 A. Again, please refer to Exhibit JES-1 for returns by customer group. As
5 shown on line 5 of Exhibit JES-1, LDS customers are sufficiently covering
6 their allocated share of the revenue requirement at present rates under the
7 Average Study.

8 Q. Are there any other reasons for not allocating a portion of the revenue
9 increase to the LDS customer class?

10 A. Yes. The LDS customer group includes many of the Company's flex rate
11 accounts. As permitted under Columbia's tariff, these customers are
12 charged rates below tariff rates due to their unique circumstances,
13 specifically their ability to leave the system through interstate or other
14 local distribution company bypass, or use of alternative fuels. Increasing
15 base rates for these flexed accounts would lead to lost load for the system
16 and ultimately increase rates for the remaining customers.

17 Q. Please describe the treatment of flex rate agreements in the development
18 of the Company's base rates.

19 A. Revenues resulting from flex rate agreements are shown in Exhibit No.
20 103. Since the flex rate agreements are individually negotiated, the
21 associated revenues were not increased as a result of the Company's rate
22 case filing.

23 Q. Do the Company's flex rate agreements benefit other customers?

1 A. Yes. Revenue collected from flex rate customers contributes to the
2 recovery of the Company's fixed costs. Without the revenues from the flex
3 rate customers, other customer groups would need to be assigned
4 additional revenue responsibility and their rates would increase.

5 Q. Will rates for LDS customers change?

6 A. The system service charges and consumption rates for existing LDS
7 customers will not change. However, as described above, the current State
8 Tax Adjustment Surcharge (STAS) rate has been set equal to 0%. This
9 change in STAS causes annual revenues for the LDS customer class to
10 increase by \$ 11,011. Additionally, the Company has proposed a revised
11 fourth tier rate for LDS. Details concerning the LDS rate structure are
12 provided in Section 8 of this testimony.

13 Q. Describe the revenue allocation to the remaining Commercial and
14 Industrial customer classes (SGS, SGDS, SCD, SDS and LGS) and the
15 residential customer classes.

16 A. The Average Study on line 5 of Exhibit JES-1 shows that the returns for all
17 C&I customer classes are greater than the system average return at current
18 rates and proposed rates. Although the residential class rate of return at
19 proposed rates is below the system average return under the Average
20 Study, the Company decided not to allocate even more of the rate increase
21 to the residential customer classes due to the principles of gradualism and
22 continuity. At current rates, the returns for the SGS, SGDS and SCD
23 customer group and the LGS customer class are only slightly above the

1 system average return; therefore the allocation of revenue requirement
2 using the Fully Forecasted Rate Year non-gas revenues was not adjusted
3 for these customer groups. Since the return for the SDS customer class is
4 considerably greater than the system average return, \$3 million was
5 reassigned from the SDS class to the residential customer group.

6 Q. Does this reallocation of revenue requirement cause the return for the
7 residential customer group to exceed the system average at proposed
8 rates?

9 A. No.

10 Q. Does this revenue reallocation help to lower the return for SDS customers
11 at proposed rates?

12 A. Yes. The return for the SDS customers is lower than it would have been
13 absent this revenue reallocation. However, the SDS return is still above
14 the system average.

15 Q. Why not reallocate more of the SDS revenue requirement to the residential
16 customer classes?

17 A. The Company is trying to strike a balance between competing rate design
18 goals of fairness and gradualism.

19 Q. In general, please describe the Company's rate design.

20 A. The customer groups explained above were used in the calculation of the
21 Company's proposed rates. Fully Forecasted Rate Year billing
22 determinants for each customer group were summed and used to compute
23 proposed rates. Details related to the development of residential,

commercial and industrial rates are provided in later sections of this testimony.

5. Residential Rate Design Option 1 - Revenue Normalization Adjustment (RNA)

Q. Please present the Company's primary residential rate design option.

A. The key elements of Rate Design Option 1 are shown below:

- System Charge = \$19.00;
- Usage Rate = \$3.8621 per Dth for all consumption;
- Revenue Normalization Adjustment (RNA);
- No usage allowance in the system charge; and
- Presented in the Company's proposed tariff.

Q. Why has the Company proposed a \$19 system charge for rate design option 1?

A. Residential customers have been billed a fixed charge of \$18.73 since October 18, 2011. Since this level of fixed fee is familiar to residential customers, the Company proposes to round this charge and bill \$19 for the system charge. This \$19.00 charge is at the low end of the system costs developed by Company witness Skirtich in Exhibit 111. Refer to Schedule 1 of Exhibit 111. Pages 14 and 17 show the range of system costs for residential customers is \$18.00 through \$33.46.

Q. Please provide an overview of the Revenue Normalization Adjustment ("RNA") proposed by the Company.

1 A. Columbia's proposed Revenue Normalization Adjustment (RNA) adjusts
2 actual non-gas distribution revenue to recover the allowed non-gas
3 distribution revenue for the non-CAP residential customer classes. The
4 RNA is designed to "break the link" between residential non-gas revenue
5 received by the Company and gas consumed by residential customers. The
6 adjustment will be calculated every six months based upon a comparison
7 of benchmark distribution revenue to the actual billed revenue.
8 Benchmark distribution revenues will be established for non-CAP
9 residential customers. The proposed RNA is a per therm adjustment that
10 will be applied to non-CAP residential service rate schedules. Columbia
11 proposes to begin the RNA with October 2013 usage. The RNA is set forth
12 beginning on Page No. 162 of the proposed tariff and is presented by
13 witness Bardes-Hasson as Exhibit 14, schedule 2.

14 Q. Will residential customers' monthly bills continue to vary with their
15 individual usage?

16 A. Yes. However, the Company's non-gas revenue from residential customers
17 will no longer depend upon the amount of natural gas consumed by each
18 residential customer.

19 Q. Please explain how the RNA "breaks the link" between residential non-gas
20 revenue and gas used by residential customers.

21 A. As part of this rate proceeding, the Company proposes to set benchmark
22 non-gas or base revenue per residential customer that is based upon
23 normal gas usage for non-CAP residential customers. This benchmark

1 base revenue per customer then becomes the allowable revenue per
2 customer for the Company. If actual base revenue per customer exceeds
3 the benchmark amount, then the Company will credit revenue to its non-
4 CAP residential customers through the RNA. Conversely, if actual base
5 revenue per customer is below the benchmark amount, then the Company
6 will collect such deficiency through the RNA.

7 Q. In the process of developing the proposed RNA, did Columbia review RNA
8 mechanisms used by other companies?

9 A. Yes. Columbia reviewed information concerning multiple revenue
10 stabilization mechanisms in a variety of states, including Massachusetts
11 and Virginia. The proposed RNA combines features from different
12 revenue normalization mechanisms and has been tailored to develop
13 Columbia's adjustment. Simplicity was a key guiding principle throughout
14 the development process. The proposed RNA is simple to understand and
15 will be relatively easy to implement because Columbia has already
16 implemented similar mechanisms in Massachusetts and Virginia.

17 Q. Which customer classes will be subject to the RNA?

18 A. The RNA will apply to non-CAP residential customers and includes the
19 following Rate Schedules:

- 20 • Rate RSS – Residential Sales Service
- 21 • Rate RDS – Residential Distribution Service (CHOICE)
- 22 • Rate RDGSS – Residential Distributed Generation Sales Service

- Rate RDGDS – Residential Distributed Generation Distribution Service

Q. Describe the method used to determine the benchmark base revenues per non-CAP residential customer.

A. The benchmark base revenues per non-CAP residential customer will be determined for two separate six month periods. The first time period, or “time period one,” includes October 1st through March 31st and the second time period, or “time period two,” includes the next six months, or April 1st through September 30th. Based upon the experience of some of the Company’s affiliates with an RNA similar to the one proposed in this case, the Company chose to determine the benchmark base revenue for two separate six month periods in order to implement the RNA factor in a timely manner.

The Company also considered annual and monthly RNA rate adjustments. The option described above with the two six month periods was selected because monthly RNA rate changes cause too much rate fluctuation and an annual RNA would not allow the Company to adjust the RNA rate in a timely fashion. A semi-annual RNA adjustment provides a compromise between the annual and monthly options and helps to moderate the magnitude of any adjustment billed through the RNA mechanism.

Q. Please continue explaining the process for determining the benchmark base revenues per non-CAP residential customer.

1 A. The first step in the process of computing benchmark base revenues is
2 multiplying the effective base rates by the corresponding Fully Forecasted
3 Rate Year billing determinants for the applicable six month period. The
4 resulting non-CAP residential base revenues are then divided by the
5 average number of non-CAP residential customers for the applicable six
6 month period to yield the benchmark base revenue per non-CAP
7 residential customer. For the purpose of calculating benchmark base
8 revenues, all customers are priced at full margin base rates.

9 Q. Provide the calculation of the proposed Benchmark Base Revenues Per
10 Customer for the non-CAP residential customers.

11

- 1 A. The Benchmark Base Revenues Per Customer (BRPC) for time periods one
2 and two are calculated below:

Calculation of Benchmark Revenue Per Customer For the Forecasted Rate Year TME June 30, 2014			
	<u>RSS, RDGSS RDS & RDGDS Base Revenue</u>	<u>RSS, RDGSS RDS & RDGDS Customers</u>	<u>Benchmark Base Revenue Per Customer</u>
October	10,450,073	361,339	\$28.92
November	15,172,605	363,375	\$41.75
December	21,888,504	365,735	\$59.85
January	29,298,111	367,165	\$79.80
February	28,782,931	368,062	\$78.20
March	<u>25,514,393</u>	<u>369,026</u>	<u>\$69.14</u>
Total	131,106,617		
Average		365,784	
BRPC-1			\$358.43
April	19,470,091	369,648	\$52.67
May	12,825,297	369,498	\$34.71
June	10,036,616	364,100	\$27.57
July	8,798,208	359,965	\$24.44
August	8,776,539	360,650	\$24.34
September	<u>8,831,987</u>	<u>360,245</u>	<u>\$24.52</u>
Total	68,738,739		
Average		364,018	
BRPC-2			\$188.83

- 3
4 Q. Is Rider USP included in the benchmark base revenue calculations for
5 non-CAP residential customers?
6 A. No. The benchmark base revenues are computed using only the system
7 charge and the base usage distribution rate.

1 Q. When does Columbia propose to reset the benchmark base revenues?

2 A. The Company would establish new benchmark base revenues with each
3 rate case filing.

4 Q. Please describe the timing of the Company's proposed RNA.

5 A. The RNA is a semi-annual mechanism. At the conclusion of each six
6 month period (March 31st for period one and September 30th for period
7 two), the Company will calculate an adjustment (RNA) to be applied to
8 non-CAP residential customers' bills beginning in the next corresponding
9 six-month period. Specifically, the RNA computed for the six-month
10 period beginning October 1, 2013 and ending March 31, 2014 will be
11 applied to the six-month period of October 1, 2014 through March 31,
12 2015. By lagging the adjustment until the next corresponding time period,
13 the Company moderates the effect of any adjustment. This is because the
14 Period 1 calculation, which encompasses the higher usage winter months,
15 will be applied to the subsequent Period 1 usage, rather than to the lower
16 use Period 2 months.

17

1 Q. Please present the Company's proposed RNA formula.

2 A. The proposed RNA formula for time period one is shown below.

3

$$\begin{array}{lcl} 4 & \text{RNA-1}_{\text{NON-CAP RES}} & = \frac{((\text{BRPC-1} - \text{ARPC-1}) * \text{ACUS-1})}{\text{FT-1}} \\ 5 & & \end{array}$$

6 Where:

7 RNA-1 = Revenue Normalization Adjustment for time period
8 one for non-CAP residential customers;

9 BRPC-1 = Benchmark Base Revenue Per Customer for non-
10 CAP residential customers for time period one;

11 ARPC-1 = Actual Base Revenue Per customer for non-CAP
12 residential customers for time period one;

13 ACUS-1 = Actual number of non-CAP residential customers for
14 time period one; ACUS will be computed using a six
15 month average.

16 FT-1 = Forecast Therms for non-CAP residential customers
17 for the six month period that the RNA will be applied.

18

1 Q. Please provide an example of the RNA calculation.

2 A. The example below shows a hypothetical RNA calculation for Period One:

Period One: (October 1, 2013 - March 31, 2014)			
Benchmark Revenue Per Customer non-CAP	\$358.43	BRPC ¹	
Actual Revenue Per Customer non-CAP	\$370.64	ARPC ¹	
Actual number of non-CAP residential Customers	365,440	ACUS ¹	
Forecast Therms for non-CAP residential customers for the six month period that the RNA will be applied	230,590,000	FT ¹	
$\text{RNA}^1 = \frac{[\text{ACUS}^1 \times (\text{BRPC}^1 - \text{ARPC}^1)]}{\text{FT}^1}$			
	(\$0.01940)	RNA ¹	
<u>Bill without RNA</u>		<u>Therms</u>	
System Charge			\$19.00
Gas Supply Charges	25	\$0.43212	\$10.80
Distribution Charges	25	\$0.38621	\$9.66
Total Bill (October 2014)			\$39.46
<u>Bill with RNA</u>		<u>Therms</u>	
System Charge			\$19.00
Gas Supply Charges	25	\$0.43212	\$10.80
Distribution Charges	25	\$0.38621	\$9.66
RNA	25	(\$0.01940)	(\$0.49)
Total Bill (October 2014)			\$38.97

*Period one will be calculated for October 1, 2013 - March 31, 2014 and will be applied to bills October 1, 2014 - March 31, 2015

3

4 Q. Does the RNA mechanism result in all non-CAP customers paying the
5 same total distribution rates?

1 A. It does not. The RNA mechanism calculates a rate that is applied to each
2 non-CAP residential customer's usage to compute an adjustment. As a
3 result, the RNA mechanism satisfies the Commission's statement that
4 there should be a balance between revenue stability and allowing
5 customers to experience any benefit from controlling their individual
6 usage and conserving.

7 Q. Does the Company propose to reconcile the RNA collections or credits in
8 future time periods?

9 A. The Company proposes to keep the RNA mechanism simple and will not
10 bill any over or under collections resulting from the RNA factors in future
11 periods.

12 Q. Has the Company proposed any changes to the calculation of quarterly
13 Rider USP as a result of the proposed RNA?

14 A. No. Since the Company's proposed RNA does not apply to CAP customers,
15 changes to Rider USP are not needed.

16 Q. Why did the Company propose to not apply the RNA to CAP customers?

17 A. CAP customers' payments are defined by their ability to pay.
18 Incorporating a charge or credit related to the RNA would ultimately flow
19 into the Rider USP charge. Columbia concluded that this added
20 unnecessary complexity to the RNA at this time.

21

22

23

1 **6. Rate Design Option 2 - Weather Normalization Adjustment (WNA).**

2 Q. Please present the Company's second rate design option.

3 A. Rate Design Option 2 is shown below:

4 ○ System Charge = \$29.00;

5 ○ Usage Rate = \$2.4579 per Dth for all consumption;

6 ○ Weather Normalization Adjustment (WNA); and

7 ○ No usage allowance in system charge.

8 Q. Please explain why the Company proposes a system charge of \$29.00 with
9 this rate design option.

10 A. Please refer to the testimony and exhibits of witness Skirtich. As
11 previously stated, the system cost for residential customers ranges from
12 \$18.00 through \$33.46. The Company's proposed residential system
13 charge with rate design option 2 falls within this range

14 Q. Why is it appropriate to propose a higher system charge for residential
15 rate design option 2 compared to option 1?

16 A. Rate design option 1 includes a Revenue Normalization Adjustment, while
17 option 2 includes only a Weather Normalization Adjustment. As a result,
18 under option 2, the Company and the customer are only protected from
19 variations due to weather. Variations in energy usage due to other factors,
20 such as the economy and end-use energy efficiency may still occur and
21 would not be normalized through the WNA. Thus, the WNA does not
22 provide the same revenue stability offered through the RNA.

23 Q. In general, please describe the WNA that the Company is proposing.

1 A. The Company's proposed WNA is a temperature-based weather
2 normalization mechanism that is applicable to residential accounts from
3 October through May of each year. The WNA methodology adjusts only
4 the temperature-sensitive portion of customers' bills to reflect normal
5 weather levels that were the basis upon which non-gas rates were
6 determined, designed and approved. By distinguishing between base load
7 and temperature-sensitive load, each customer's bill will be calculated to
8 mitigate the undesirable impacts of warmer than normal, or colder than
9 normal weather. In essence, the WNA permits the Company to calculate
10 the non-gas portion of customers' bills based upon normal weather.
11 Columbia proposes to apply the WNA to residential customers' bills for the
12 period of October through May. The WNA will be included on customers'
13 bills on a cents per therm basis during the period for which the customer is
14 billed.

15 Q. Why does the Company propose to apply the WNA adjustment to the bills
16 for the period of October through May?

17 A. The months of June, July, August and September have been excluded from
18 the WNA adjustment because historical data shows that no significant
19 weather variation occurs during these months. Conversely, during the
20 period of October through May, the Company can reasonably expect actual
21 Heating Degree Days (HDDs) to vary from normal HDDs.

22 Q. What customers will be subject to the WNA?

1 A. The WNA will apply to all residential customers and includes the following
2 Rate Schedules:

- 3 • Rate RSS – Residential Sales Service
- 4 • Rate RDS – Residential Distribution Service (CHOICE)
- 5 • Rate RDGSS – Residential Distributed Generation Sales Service
- 6 • Rate RDGDS – Residential Distributed Generation Distribution
7 Service
- 8 • Rate CAP – Customer Assistance Program

9 Q. Will the WNA apply to both gas and non-gas charges?

10 A. No. The Company's proposed WNA will only be used to calculate the non-
11 gas distribution charges, including Rider USP by adjusting usage to reflect
12 what the usage would have been if weather had been normal during the
13 billing period. The system charge will not be adjusted as a result of the
14 WNA. Similarly, the WNA will not apply to recovery of gas costs. Gas cost
15 recovery rates will continue to be billed using actual (non-normalized)
16 usage.

17 Q. In the process of developing a proposed WNA, did Columbia consider
18 weather normalization adjustment tariffs used by other companies?

19 A. Yes. Columbia looked at companies, including Philadelphia Gas Works
20 ("PGW"), Columbia Gas of Maryland, Columbia Gas of Kentucky and
21 Columbia Gas of Virginia. Columbia combined different features of these
22 mechanisms to develop a proposal for its residential customers.

1 Q. How will the Company define normal weather for the WNA mechanism?

2 A. WNA normal weather will be defined using 20 years to be consistent with
3 the Fully Forecasted Rate Year presented in the testimony of Company
4 witness Efland (Columbia Statement No. 2). Any other definition of
5 weather would cause discontinuity between the weather normalized billing
6 determinants used to design rates and the WNA mechanism.

7 Q. Please present the formula that the Company proposes to use to compute
8 weather normalized billing usage.

9 A. $WNBT = [(AMT - BLMT) * (NHDD/AHDD)] + BLMT$, where

10 $WNBT =$ Weather Normalized Billing Therms

11 $AMT =$ Actual Monthly Therms

12 $BLMT =$ Base Load Monthly Therms

13 $NHDD =$ Normal Heating Degree Days

14 $AHDD =$ Actual Heating Degree Days

15 Q. Will the weather normalized billing calculation be performed for each
16 residential customer?

17 A. Yes. The computation will be performed individually for each customer
18 subject to WNA.

19 Q. How will a customer's Base Load Monthly Therms (BLMT) be
20 determined?

21 A. For each customer, the BLMT will be established using their average daily
22 consumption from the billing system, measured in therms, for the two
23 months with the lowest consumption per billing day for the three months

1 of July, August, and September. These months have little or no
2 temperature sensitive consumption. The average base load per day
3 information for each customer will be updated annually.

4 Q. How will the Company determine a customer's BLMT if sufficient usage
5 data is not available?

6 A. If a customer's BLMT cannot be determined as previously described, then
7 the Company will use the base load history for the applicable premise. If
8 that information is not available, as would be the case for a new residence,
9 then the Company will use the overall base load average for the class.

10 Q. Define Actual Heating Degree Days (AHDD).

11 A. AHDD is the average temperature for each day subtracted from a reference
12 temperature of 65 degrees, but not less than zero, for the cumulative days
13 of a customer's cycle billing unit.

14 Q. How will Normal Heating Degree Days (NHDD) be computed?

15 A. Normal heating degree days shall be computed using the same
16 methodology established in the Company's most recent rate case and used
17 to determine the adjusted throughput usage and revenue requirements.

18 Q. Does Columbia propose to use individual weather stations for the heating
19 degree day calculations?

20 A. Yes. The Company plans to use available weather data from the National
21 Oceanic and Atmospheric Administration (NOAA) weather stations to
22 determine actual average daily temperatures. Customer accounts will be

1 assigned to NOAA weather stations based on their geographic location and
2 proximity to the weather station.

3 Q. How will Weather Normalized Billing Therms (WNBT) be used to compute
4 residential customers' bills?

5 A. Actual Monthly Therms (AMT) will be subtracted from WNBT to compute
6 Weather Normalized Adjustment Therms (WNAT) as shown in the
7 formula below:

$$8 \quad \text{WNAT} \quad \quad \quad \approx \quad \quad \text{WNBT} - \text{AMT}$$

9 The Weather Normalized Adjustment Therms will then be multiplied by
10 the residential base usage rate to compute a Weather Normalization
11 Adjustment (WNA) amount that will be charged or credited to residential
12 customers.

13 Q. How will the WNA appear on a residential customer's bill?

14 A. The WNA will be a separate line item on a residential customer's bill.
15 Columbia favors the simplicity and clarity of providing customers with a
16 dollar amount associated with the weather normalization adjustment.

17

1 Q. Provide a simple WNA example.

2 A. Refer to the example below:

Actual Monthly Therms	25	AMT	
Base Load Monthly Therms	15	BLMT	
Normal Heating Degree Days for billing cycle	175	NHDD	
Actual Heating Degree Days for billing cycle	184	AHDD	
Weather Normalized Billing Therms (WNBT)			
WNBT = [(AMT-BLMT) x (NHDD / AHDD)] + BLMT			
[(25-15) x (175/184)]+15 =		24.5	Therms
Weather Normalized Adjustment Therms (WNAT)			
WNAT = WNBT – AMT			
24.5 Therms - 25 Therms =		(0.5)	Therms
<u>October Bill without WNA</u>		<u>Therms</u>	
System Charge			\$29.00
Gas Supply Charges	25	\$0.43212	\$10.80
Distribution Charges	25	\$0.24579	\$6.14
Total Bill			\$45.95
<u>October Bill with WNA</u>		<u>Therms</u>	
System Charge			\$29.00
Gas Supply Charges	25	\$0.43212	\$10.80
Distribution Charges	25	\$0.24579	\$6.14
WNA	(0.5)	\$0.24579	(\$0.12)
Total Bill			\$45.82

3
4 As is the case with the RNA, the WNA adjustment is applied to each
5 individual customer's usage, and thus does maintain the customer's ability
6 to affect their total distribution charges through changes in usage.
7

1 Q. Does the Company propose any additional reporting related to the WNA?

2 A. The Company proposes to file all Weather Normalization Adjustments
3 with the Commission on an annual basis. Exhibit PAS-1 provides an
4 example of the type of information that the Company would provide in an
5 annual WNA filing. The information in this exhibit is submitted by
6 Columbia Gas of Kentucky on an annual basis to the Kentucky Public
7 Service Commission.

8 Q. Will Columbia's Quarterly Gas Cost Rate and 1307(f) filing change as a
9 result of implementing the proposed WNA?

10 A. No.

11 Q. Does Columbia propose a dead band percentage similar to PGW's tariff?

12 A. No. The Company believes that the WNA mechanism is easier to
13 understand and explain to customers without the use of the dead band.
14 Simplicity is a key rate design consideration for Columbia.

15
16 **7. Rate Design Option 3 - Levelized Distribution Charge (LDC)**

17 Q. Please present rate design option 3.

18 A. Residential Rate design option 3 is shown below:

- 19 ○ System Charge = \$ 45.49;
20 ○ No Usage Distribution Charge Per Therm Rate; and
21 ○ Levelized Distribution Charge (LDC).

22 Q. Please provide the Company's rationale for proposing a Levelized
23 Distribution Charge (LDC) for residential customers.

1 A. As witness Kempic discusses in his testimony, the Company considers the
2 LDC to be a simpler rate design that is directly related to the manner in
3 which Columbia incurs costs to provide distribution service.
4

5 **8. Proposed Commercial & Industrial Base Rates**

6 Q. Does Columbia propose to change the annual customer class rate schedule
7 break points for commercial and industrial ("C&I") customers?

8 A. Yes. Columbia proposes to slightly change the annual C&I rate schedule
9 break points.

10 Q. Please elaborate.

11 A. In Docket No. 2010-2215623, Columbia converted from Mcf billing based
12 upon volumes to therm billing. As part of this conversion process, the
13 annual C&I customer rate schedule break points were converted from
14 MCF to therms using a conversion factor of 1.073. Columbia proposes to
15 round these break points as shown on Exhibit No. 103, Schedule 8 in the
16 column labeled "Description." A summary of the existing and proposed
17 break points is shown in the chart below:

Rate Schedule(s)	Existing Annual Break Point (therms)	Proposed Annual Break Point (therms)
SGSS,SCD,SGDS	= 6,438	<= 6,440
SGSS,SCD,SGDS	>= 6,438 & <= 64,380	> 6,440 & <=64,400
LGSS,SDS	>= 64,380 & < 107,300	> 64,400 & <=110,000
LGSS,SDS	>= 107,300 & < 536,500	> 110,000 & <=540,000
MLSS,MLDS	>= 268,250 & < 536,500	> 274,000 & <=540,000
LGSS,MLSS,LDS,MLDS	>= 536,500 & < 1,072,989	> 540,000 & <= 1,074,000
LGSS,MLSS,LDS,MLDS	>= 1,072,989 & < 3,219,000	> 1,074,000 & <=3,400,000
LGSS,MLSS,LDS,MLDS	>= 3,219,000 & < 7,510,990	> 3,400,000 & <=7,500,000
LGSS,MLSS,LDS,MLDS	>= 7,510,989	> 7,500,000

1

2 Q. Why is Columbia proposing to change the annual C&I rate schedule break
3 points?

4 A. The new rate schedule break points are intended to increase the simplicity
5 of the rate design. As a result of the change to therm billing, the prior
6 break points which were originally established on a volumetric (Mcf) basis
7 were no longer round numbers. That added unnecessary complexity to the
8 billing process for the both the Company and consumers.

9 Q. How did Columbia select the proposed annual break points?

1 A. The Company attempted to minimize impact to customers related to
2 rounding the annual break points by analyzing consumption data for the
3 twelve month period ended May 2012.

4 Q. Given the historic test year data, how many customers are impacted by the
5 break point changes?

6 A. Please refer to the testimony of witness Bell for the number of customers
7 impacted by rounding the annual break points.

8 Q. Have the per Dth block sizes for the LGSS rate schedule been changed?

9 A. Yes. Please refer to Exhibit 103, Schedule 8, page 3 for the new block
10 sizes. Again, the Company proposes to round these block sizes for
11 simplicity.

12 Q. What are the proposed commercial and industrial system charges?

13 A. The proposed C&I system charges are shown on Schedule 8 of Exhibit 103
14 in column 7.

15 Q. Does Columbia propose to increase the system charges for small
16 commercial and industrial customers?

17 A. Yes. The proposed system charge for SGSS, SCD and SGDS customers
18 using 6,400 therms or less annually is \$30. A \$45 system charge has been
19 proposed for SGSS, SCD and SGDS customers using more than 6,400
20 therms annually. These system charges fall within the range of customer
21 costs computed by witness Skirtich on Exhibit 111, Schedule 1, pages 14
22 and 17.

1 Q. Please explain the Company's proposal for system charges billed to LGSS
2 and SDS customers.

3 A. Currently, LGSS and SDS customers consuming at least 64,400 therms,
4 but no more than 540,000 therms annually are billed the same system
5 charges. The Company proposes to maintain the same level of system
6 charge for these customer groups. The proposed system charges are \$150
7 for customers consuming less than 110,000 therms annually and \$550 for
8 customers consuming between 110,000 and 540,000. The range of system
9 costs computed by witness Skirtich for the LGSS and SDS customer classes
10 is \$108.83 through \$879.19. These costs are shown on Exhibit 111,
11 Schedule 1, pages 14 and 17.

12 Q. Has the Company proposed to change the system costs for the remaining
13 LGSS customers?

14 A. Yes. The Company proposes to increase the system charge for LGSS
15 customers consuming between 540,000 and 1,074,000 therms annually to
16 \$1,227. This change causes the system charges for the larger tiers of the
17 LGSS rate schedule to be consistent with the LDS rate schedule. As shown
18 on Exhibit 111, the system cost for the LDS customers ranges from \$779.84
19 to \$2,714.17.

20 Q. How were the usage rates calculated for rate schedules SGSS, SCD, SGDS,
21 LGSS and SDS?

22 A. The revenue requirements not collected through the system charge were
23 divided by the Fully Forecast Rate Year therms to compute the

1 consumption rates. The current rate design aligns the LGSS and SDS rate
2 structures by setting the tailblock rate of the LGSS rate equal to the SDS
3 consumption rate. The Company proposes to maintain this alignment of
4 rates.

5 Q. Is the Company maintaining the rate distinction for SGDS Priority 1 and
6 SGDS Non-Priority 1 customers?

7 A. Yes. Priority 1 customers will continue to be charged for the recovery of
8 the Company's purchased gas demand costs pursuant to the Company's
9 Purchased Gas Cost Rider.

10 Q. Have the rates for Large Distribution Service been changed?

11 A. Yes. The Company proposes to add a rate differential for usage billed in
12 the fourth tier of the LDS rate schedule.

13 Q. Please explain.

14 A. Rate schedule LDS includes four tiers of usage. The four tiers include
15 ascending system charges, and three of the four tiers have descending
16 usage rates. Consumption for customers in the third and fourth tiers
17 currently is billed at the same per Dth rate. Customers with consumption
18 is excess of 7,500,000 therms annually should not pay a higher system
19 charge and the same consumption rate as customers consuming less than
20 7,500,000 therms annually.

21 Q. Did rate schedule LDS previously have four tiers for the usage rate?

22 A. Yes. Prior to the implementation of rates approved in Docket R-2008-
23 2011621, rate schedule LDS had four usage tiers.

1 Q. What are the Company's proposed usage rates for rate schedule LDS?

2 A. Refer to the information shown below:

<u>Annual Usage (Therms)</u>	<u>\$/Dth</u>
540,000 - 1,074,000	\$0.9270
1,074,000 - 3,400,000	\$0.8114
3,400,000 - 7,500,000	\$0.6716
> 7,500,000	\$0.4061

3 Q. Please describe how the Company determined the fourth tier rate?

4 A. The fourth tier rate was calculated based upon a two step process.
5 Initially, Columbia evaluated the difference between the first and second
6 tiers and the second and third tiers. The difference between the first two
7 tiers is almost 0.12 and the third tier is lower by about 0.14. In order to
8 compute a fourth tier 0.16 was subtracted from 0.6716. The result is
9 0.5116.

10 Q. Please explain the next step in this rate computation.

11 A. As noted in the Average Cost of Service Study that the Company is
12 principally relying upon in this case, the LDS rate class is producing
13 returns that are above the system average. As this is a rate that is being
14 reintroduced and there is currently no usage at this rate block, the
15 Company proposes to adjust the rate down further in order to reflect the
16 system average return. Mr. Skirtich's Exhibit JES-5 provides the

1 information regarding the surplus revenue produced from this class under
2 the Average Study. This information was used to adjust the 4th block rate.

3 Q. Please explain how the 4th block rate was adjusted.

4 A. Refer to witness Skirtich's Exhibit JES-5. Column 3 shows that using the
5 Average Study, the LDS customer class is contributing approximately
6 \$2.08 million above the required return for the customer class. Assume
7 that this \$2.08 million revenue surplus is used to lower the LDS rates. For
8 this rate calculation the Company assigned half of the surplus to the
9 system charges and assigned the remaining amount, \$1.04 million to the
10 usage charges. During the Fully Forecasted Rate Year, the LDS customer
11 class consumed 9,886,942 Dth. An average usage rate of \$0.1055 per Dth
12 is computed when half of the revenue surplus is divided by the annual
13 usage for the LDS customer class. The result of subtracted the average
14 usage rate (\$0.1055) from the fourth block rate (\$0.5116) computed above
15 is \$0.4061 and this is the Company's proposed rate for the fourth usage
16 tier of the LDS rate schedule.

17 Q. Has the Company proposed an increase to the volumetric base rate for
18 Mainline Service customers?

19 A. No. The Allocated Cost of Service results presented by witness Skirtich
20 indicate that the return for Mainline Service customers is well in excess of
21 the average rate of return.

22 Q. What are the usage distribution rates proposed by the Company for C&I
23 customers?

1 A. Please refer to Schedule 8 of Exhibit 103 for the Company's proposal. The
2 usage distribution rates are shown in column 7.

3
4 **9. Gas Procurement Charge (GPC)**

5 Q. Why are you calculating a separate surcharge rate for a Gas Procurement
6 Charge (GPC)?

7 A. The Pennsylvania Public Utility Commission, on June 23, 2011, per Docket
8 L-2008-2069114, adopted a final rulemaking order which was designed to
9 ensure that consumers of natural gas will be able to shop for gas that is
10 marketed on a level playing field for all market participants. As it relates to
11 the "price to compare" the rulemaking requires the Natural Gas
12 Distribution Company (NGDC) to remove natural gas procurement costs
13 from base rates, excluding those costs related to the administration of firm
14 storage and transportation capacity, and to recover those fuel acquisition
15 costs as part of the "price to compare," on a revenue neutral basis under
16 Section 510 of the Public Utility Code via an automatic adjustment
17 surcharge. Exhibit PAS-2 provides a calculation of the GPC.

18 Q. What costs are included in the Gas Procurement Charge?

19 A. The GPC includes the labor and benefits costs associated with gas
20 procurement activities. As shown on Exhibit PAS-2, labor and benefits
21 costs have been further defined by function and include external legal
22 costs.

23 Q. How are you proposing to recover these costs?

1 A. Per Docket L-2008-2069114, these costs will be recovered via an
2 automatic adjustment surcharge. The GPC is not subject to reconciliation
3 and will only be recalculated in a base rate case.

4 Q. Will all customers pay the GPC?

5 A. The following Rate Schedules will pay the GPC:

- 6 • RSS;
- 7 • RDGSS;
- 8 • SGSS;
- 9 • LGSS;
- 10 • MLSS; and
- 11 • CAP, if a Natural Gas Supplier is not currently providing natural gas
12 to the CAP aggregation group.

13 Q. Is the Company presenting a tariff for the GPC?

14 A. Yes. Witness Bardes-Hasson is sponsoring Rider GPC as the Twelfth
15 Revised Page No. 160 of Columbia's tariff.

16 Q. How does the GPC impact the Company's Price to Compare?

17 A. The GPC rate will be added to the current price to compare calculation on
18 a quarterly basis and reflected on the bill as a component of the price to
19 compare.

20 Q. What is included in the current Price to Compare?

21 A. The Price to Compare equals the quarterly Purchase Gas Commodity Cost
22 (PGCC) plus the Off System Sales Credit plus the Capacity Release Credit

1 plus the Choice Credit plus the Uncollectible Expense on Gas Costs
2 (Merchant Function Charge).
3

4 **10. Revenue Proof and Bill Impacts**

5 Q. Provide a proof of the future test year base revenue requirement by rate
6 schedule.

7 A. Please refer to witness Bell's Exhibit No. 103 for a proof of the test year
8 base revenue requirement by rate schedule.

9 Q. Please summarize the class-level bill impacts resulting from the
10 Company's proposal?

11 A. The class average bill impacts are shown on Exhibit No. 103, Schedule 8,
12 column 8.

13 Q. Is the Company providing graphs of the bill impacts?

14 A. Yes. Please refer to Exhibit No. 111, Schedule No. 5, Pages 1 through 9. A
15 graph for Residential Sales Service is shown on page 1. Pages 2 through 9
16 provide graphs for Small General Sales Service and Large General Sales
17 Service.

18 Q. What is the range of monthly bill impacts for residential customers?

19 A. Please refer to Exhibit No. 111, Schedule No. 6, Page 1. This schedule
20 shows monthly bills impacts for residential customers at various usage
21 levels.

22 Q. Has the Company performed bill impact analyses for commercial and
23 industrial customers?

1 A. Yes. Please refer to Exhibit No. 111, Schedule No. 6, Pages 2 through 9.
2 These schedules provide monthly bill impacts for Small General Sales
3 Service and Large General Sales Service customers at various consumption
4 levels.

5 Q. Has the Company computed bill impacts for residential rate design
6 options 2 and 3?

7 A. Yes. Please refer to Exhibits PAS-3 and PAS-4 for these bill impacts.

8 Q. Does this conclude your testimony?

9 A. Yes.

**Columbia Gas[®]
of Kentucky**
A NiSource Company

P.O. Box 14241
2001 Mercer Road
Lexington, KY 40512-4241

RECEIVED

JUN 01 2011

**PUBLIC SERVICE
COMMISSION**

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
P. O. Box 615
Frankfort, Kentucky 40602

June 1, 2011

Dear Mr. Derouen:

Pursuant to the Commission's Order of December 1, 1997 in Case No. 97-299, Columbia Gas of Kentucky, Inc. hereby submits its annual report on the operation of the Weather Normalization Adjustment (WNA).

If you have any questions, please call me at (859) 288-0242. Thank you.

Sincerely,


Judy M. Cooper

Attachment

COLUMBIA GAS OF KENTUCKY, INC.

WNA Summary Report

2010-2011 Heating Season vs. 2009-2010

December - April

RESIDENTIAL		December	January	February	March	April	2010-2011 Season Total	2009-2010 Season Total
WNA Customers		119,439	119,981	119,978	119,572	118,984	119,591	120,262
Total Customers		121,780	122,338	122,323	121,904	121,291		
WNA Revenue	\$	(325,979)	(791,510)	(377,328)	229,191	(12,850)	(1,278,475)	(987,600)
WNA Vol. Adjustment	Mcf	(174,181)	(422,928)	(201,618)	122,464	(6,866)	(683,128)	(527,705)
Avg. WNA./Heating Customer	\$	(2.73)	(6.60)	(3.14)	1.92	(0.11)	(10.69)	(8.21)

COMMERCIAL

WNA Customers		13,513	13,599	13,620	13,580	13,481	13,559	13,645
Total Customers		14,091	14,176	14,198	14,162	14,066		
WNA Revenue	\$	(162,631)	(392,377)	(187,027)	107,056	5,142	(629,836)	(519,690)
WNA Vol. Adjustment	Mcf	(90,084)	(216,528)	(103,038)	59,083	2,881	(347,685)	(286,883)
Avg. WNA./Heating Customer	\$	(12.04)	(28.85)	(13.73)	7.88	0.38	(46.45)	(38.09)

TOTAL

WNA Revenue		(488,610)	(1,183,887)	(564,354)	336,247	(7,707)	(1,908,311)	(1,507,290)
WNA Volume Adjustment		(264,264)	(639,456)	(304,655)	181,547	(3,985)	(1,030,814)	(814,588)

WEATHER

Billing HDD's - Actual		861	1197	969	607	426	4,060	3,992
Billing HDD's - Normal		731	957	876	703	437	3,704	3,717
Warmer (Colder) Than Normal		-17.8%	-25.1%	-10.6%	13.7%	2.5%	-9.6%	-7.4%

Calendar HDD's - Actual		1151	1121	732	574	217	3,795	3,771
Calendar HDD's - Normal		874	927	765	602	278	3,446	3,446
Warmer (Colder) Than Normal		-31.7%	-20.9%	4.3%	4.7%	21.9%	-10.1%	-9.4%

CUSTOMER SERVICE

Total No. of WNA Inquires		0	0	0	0	0	0	0
No. of Inquires not satisfied		0	0	0	0	0	0	0

COLUMBIA GAS OF KENTUCKY, INC.

WNA Summary Report

December, 2010

RESIDENTIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		93,351	91,301	
Revenue	\$	11,086,802	10,844,416	(242,387)
Volume	Mcf	1,095,781	966,267	(129,515)
Avg. WNA./Heating Customer				

COMMERCIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		9,824	9,425	
Revenue	\$	4,885,362	4,779,797	(105,565)
Volume	Mcf	524,638	466,485	(58,153)
Avg. WNA./Heating Customer				

RESIDENTIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		28,429	28,138	
Revenue	\$	1,103,096	1,019,503	(83,593)
Volume	Mcf	368,142	323,476	(44,666)
Avg. WNA./Heating Customer				

COMMERCIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		4,251	4,073	
Revenue	\$	622,936	572,191	(50,745)
Volume	Mcf	279,232	251,278	(27,954)
Avg. WNA./Heating Customer				

COMMERCIAL TRANSPORTATION		Actual	Weather Normalization	Impact of WNA
No. of Customers		16	15	
Revenue	\$	42,606	36,285	(6,321)
Volume	Mcf	28,443	24,466	(3,977)
Avg. WNA./Heating Customer				

Total Res./Comm. Revenue		17,740,802	17,252,193	(488,610)
Total Res./Comm. Volumes		2,296,236	2,031,972	(264,264)

COLUMBIA GAS OF KENTUCKY, INC.

WNA Summary Report

January, 2011

RESIDENTIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		93,290	91,237	
Revenue	\$	16,340,419	15,751,193	(589,226)
Volume	Mcf	1,683,742	1,368,901	(314,841)
Avg. WNA./Heating Customer				

COMMERCIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		9,866	9,486	
Revenue	\$	7,277,601	7,026,471	(251,130)
Volume	Mcf	793,070	654,729	(138,341)
Avg. WNA./Heating Customer				

RESIDENTIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		29,048	28,744	
Revenue	\$	1,495,466	1,293,182	(202,284)
Volume	Mcf	566,774	458,687	(108,087)
Avg. WNA./Heating Customer				

COMMERCIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		4,274	4,098	
Revenue	\$	878,589	742,143	(136,446)
Volume	Mcf	420,406	345,241	(75,164)
Avg. WNA./Heating Customer				

COMMERCIAL TRANSPORTATION		Actual	Weather Normalization	Impact of WNA
No. of Customers		16	15	
Revenue	\$	45,541	40,740	(4,801)
Volume	Mcf	29,324	26,301	(3,023)
Avg. WNA./Heating Customer				

Total Res./Comm. Revenue		26,037,616	25,056,013	(1,183,887)
Total Res./Comm. Volumes		3,493,315	2,853,859	(639,456)

COLUMBIA GAS OF KENTUCKY, INC.

WNA Summary Report

February, 2011

RESIDENTIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		93,331	91,294	
Revenue	\$	13,922,952	13,641,723	(281,229)
Volume	Mcf	1,412,853	1,262,584	(150,269)
Avg. WNA./Heating Customer				

COMMERCIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		9,856	9,460	
Revenue	\$	6,338,804	6,216,712	(122,092)
Volume	Mcf	687,468	620,211	(67,257)
Avg. WNA./Heating Customer				

RESIDENTIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		28,992	28,684	
Revenue	\$	1,315,609	1,219,511	(96,099)
Volume	Mcf	474,338	422,990	(51,348)
Avg. WNA./Heating Customer				

COMMERCIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		4,326	4,146	
Revenue	\$	774,001	709,209	(64,793)
Volume	Mcf	363,561	327,868	(35,693)
Avg. WNA./Heating Customer				

COMMERCIAL TRANSPORTATION		Actual	Weather Normalization	Impact of WNA
No. of Customers		16	14	
Revenue	\$	44,761	44,619	(142)
Volume	Mcf	25,899	25,811	(88)
Avg. WNA./Heating Customer				

Total Res./Comm. Revenue		22,396,126	21,831,774	(564,354)
Total Res./Comm. Volumes		2,964,120	2,659,464	(304,655)

COLUMBIA GAS OF KENTUCKY, INC.

WNA Summary Report

March, 2011

RESIDENTIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		92,971	90,945	
Revenue	\$	8,047,674	8,216,966	169,293
Volume	Mcf	862,474	952,932	90,458
Avg. WNA./Heating Customer				

COMMERCIAL TARIFF				
No. of Customers		9,847	9,451	
Revenue	\$	3,565,337	3,634,651	69,314
Volume	Mcf	420,097	458,280	38,183
Avg. WNA./Heating Customer				

RESIDENTIAL CHOICE				
No. of Customers		28,933	28,627	
Revenue	\$	937,313	997,212	59,899
Volume	Mcf	295,561	327,566	32,006
Avg. WNA./Heating Customer				

COMMERCIAL CHOICE				
No. of Customers		4,297	4,118	
Revenue	\$	492,713	529,040	36,327
Volume	Mcf	237,229	257,240	20,012
Avg. WNA./Heating Customer				

COMMERCIAL TRANSPORTATION				
No. of Customers		18	11	
Revenue	\$	39,864	41,279	1,415
Volume	Mcf	21,818	22,706	888
Avg. WNA./Heating Customer				

Total Res./Comm. Revenue		13,082,901	13,419,148	336,247
Total Res./Comm. Volumes		1,837,178	2,018,725	181,547

COLUMBIA GAS OF KENTUCKY, INC.
WNA Summary Report
April, 2011

RESIDENTIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		92,565	90,561	
Revenue	\$	6,040,126	6,031,564	(8,562)
Volume	Mcf	606,422	601,847	(4,575)
Avg. WNA./Heating Customer				

COMMERCIAL TARIFF		Actual	Weather Normalization	Impact of WNA
No. of Customers		9,774	9,380	
Revenue	\$	2,590,261	2,592,972	2,711
Volume	Mcf	299,215	300,708	1,493
Avg. WNA./Heating Customer				

RESIDENTIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		28,726	28,423	
Revenue	\$	772,794	768,507	(4,288)
Volume	Mcf	206,936	204,645	(2,291)
Avg. WNA./Heating Customer				

COMMERCIAL CHOICE		Actual	Weather Normalization	Impact of WNA
No. of Customers		4,275	4,094	
Revenue	\$	381,003	382,768	1,764
Volume	Mcf	169,467	170,439	972
Avg. WNA./Heating Customer				

COMMERCIAL TRANSPORTATION		Actual	Weather Normalization	Impact of WNA
No. of Customers		17	7	
Revenue	\$	29,086	29,752	667
Volume	Mcf	15,679	16,095	416
Avg. WNA./Heating Customer				

Total Res./Comm. Revenue		9,813,271	9,805,563	(7,707)
Total Res./Comm. Volumes		1,297,718	1,293,733	(3,985)

Columbia Gas of Pennsylvania, Inc
Gas Procurement Charge

1 Labor and Benefits ⁽¹⁾

2	Accounting Support	\$	23,497.11	
3	Gas Supply Support	\$	342,953.42	
4	Legal Support	\$	12,818.74	
5	Regulatory Support	\$	60,496.74	
6	Total Labor and Benefits	\$	439,766.02	
7				
8	Outside Services - Legal Support	\$	25,521.27	
9				
10	TOTAL (line 6 + line 8)	\$	465,287.00	
11				
12	Total Sales (Therms)		323,191,965	⁽²⁾
13				
14	Gas Procurement Charge (Line 10 / Line 12)	\$	0.001440	per /therm
15	Gas Procurement Charge (Line 14 * 10)	\$	0.014400	per / Dthm

(1) Labor charges include payroll, benefits and taxes.

(2) Fully Forecasted Rate Year Gas Service Sales per Exhibit 103, page 14, line 26

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPARISON OF MONTHLY BILLS
RESIDENTIAL SALES SERVICE - Option 2 (WNA)

	PRESENT RATES	PROPOSED RATES
CUSTOMER CHARGE	\$ 18.73	\$ 29.00
DISTRIBUTION CHARGE - FIRST 21 THMS	\$ -	\$ 0.24579
DISTRIBUTION CHARGE - OVER 21 THMS	\$ 0.26708	\$ 0.24579
RIDER USP	\$ 0.03595	\$ 0.04544
RIDER PGCC	\$ 0.37475	\$ 0.37475
RIDER PGDC	\$ 0.11717	\$ 0.11717
UNBUNDLED UNCOLLECTIBLES	\$ 0.00590	\$ 0.00590
GAS PROCUREMENT CHG (NON-CAP)	\$ -	\$ 0.00144
COMMODITY E-FACTOR	\$ (0.05980)	\$ (0.05980)
STATE TAX ADJUSTMENT	-0.116%	0.000%

THM	Present \$	Proposed \$	Present \$/Thm	Proposed \$/Thm	DIFFERENCE	
					Amount \$	Percent %
Usage						
0	18.71	29.00			10.29	55.00%
1	\$ 19.18	29.73	19.18	29.73	10.55	55.01%
3	\$ 20.13	31.19	6.71	10.40	11.06	54.94%
5	\$ 21.08	32.66	4.22	6.53	11.58	54.93%
7	\$ 22.03	34.12	3.15	4.87	12.09	54.88%
8	\$ 22.50	34.85	2.81	4.36	12.35	54.89%
10	\$ 23.45	36.30	2.35	3.63	12.85	54.80%
15	\$ 25.82	39.96	1.72	2.66	14.14	54.76%
21	\$ 28.66	44.35	1.36	2.11	15.69	54.75%
25	\$ 31.62	47.27	1.26	1.89	15.65	49.49%
30	\$ 35.33	50.92	1.18	1.70	15.59	44.13%
35	\$ 39.03	54.57	1.12	1.56	15.54	39.82%
40	\$ 42.73	58.23	1.07	1.46	15.50	36.27%
45	\$ 46.44	61.89	1.03	1.38	15.45	33.27%
50	\$ 50.14	65.53	1.00	1.31	15.39	30.69%
60	\$ 57.55	72.84	0.96	1.21	15.29	26.57%
70	\$ 64.95	80.15	0.93	1.15	15.20	23.40%
80	\$ 72.36	87.46	0.90	1.09	15.10	20.87%
90	\$ 79.77	94.76	0.89	1.05	14.99	18.79%
100	\$ 87.18	102.07	0.87	1.02	14.89	17.08%
150	\$ 124.22	138.60	0.83	0.92	14.38	11.58%
200	\$ 161.25	175.14	0.81	0.88	13.89	8.61%
250	\$ 198.29	211.68	0.79	0.85	13.39	6.75%
300	\$ 235.32	248.21	0.78	0.83	12.89	5.48%
350	\$ 272.37	284.74	0.78	0.81	12.37	4.54%
400	\$ 309.40	321.27	0.77	0.80	11.87	3.84%
450	\$ 346.44	357.81	0.77	0.80	11.37	3.28%
500	\$ 383.47	394.35	0.77	0.79	10.88	2.84%
600	\$ 457.55	467.42	0.76	0.78	9.87	2.16%
700	\$ 531.62	540.48	0.76	0.77	8.86	1.67%
800	\$ 605.70	613.55	0.76	0.77	7.85	1.30%
900	\$ 679.77	686.62	0.76	0.76	6.85	1.01%
1000	\$ 753.85	759.69	0.75	0.76	5.84	0.77%
1500	\$ 1,124.21	1,125.04	0.75	0.75	0.83	0.07%

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPARISON OF MONTHLY BILLS
RESIDENTIAL SALES SERVICE - Option 3 LDC

	PRESENT RATES	PROPOSED RATES
CUSTOMER CHARGE	\$ 18.73	\$ 46.49
DISTRIBUTION CHARGE - FIRST 21 THMS	\$ -	\$ -
DISTRIBUTION CHARGE - OVER 21 THMS	\$ 0.26708	\$ -
RIDER USP	\$ 0.03595	\$ 0.03744
 RIDER PGCC	 \$ 0.37475	 \$ 0.37475
RIDER PGDC	\$ 0.11717	\$ 0.11717
UNBUNDLED UNCOLLECTIBLES	\$ 0.00590	\$ 0.00590
GAS PROCUREMENT CHG (NON-CAP)	\$ -	\$ 0.00144
COMMODITY E-FACTOR	\$ (0.05980)	\$ (0.05980)
 STATE TAX ADJUSTMENT	 -0.116%	 0.000%

THM	Present \$	Proposed \$	Present \$/Thm	Proposed \$/Thm	DIFFERENCE	
					Amount \$	Percent %
Usage						
0	18.71	46.49			27.78	148.48%
1	\$ 19.18	46.97	19.18	46.97	27.79	144.89%
3	\$ 20.13	47.92	6.71	15.97	27.79	138.05%
5	\$ 21.08	48.88	4.22	9.78	27.80	131.88%
7	\$ 22.03	49.83	3.15	7.12	27.80	126.19%
8	\$ 22.50	50.31	2.81	6.29	27.81	123.60%
10	\$ 23.45	51.25	2.35	5.13	27.80	118.55%
15	\$ 25.82	53.64	1.72	3.58	27.82	107.75%
21	\$ 28.66	56.51	1.36	2.69	27.85	97.17%
25	\$ 31.62	58.42	1.26	2.34	26.80	84.76%
30	\$ 35.33	60.79	1.18	2.03	25.46	72.06%
35	\$ 39.03	63.18	1.12	1.81	24.15	61.88%
40	\$ 42.73	65.57	1.07	1.64	22.84	53.45%
45	\$ 46.44	67.95	1.03	1.51	21.51	46.32%
50	\$ 50.14	70.33	1.00	1.41	20.19	40.27%
60	\$ 57.55	75.11	0.96	1.25	17.56	30.51%
70	\$ 64.95	79.87	0.93	1.14	14.92	22.97%
80	\$ 72.36	84.65	0.90	1.06	12.29	16.98%
90	\$ 79.77	89.41	0.89	0.99	9.64	12.08%
100	\$ 87.18	94.18	0.87	0.94	7.00	8.03%
150	\$ 124.22	118.03	0.83	0.79	(6.19)	-4.98%
200	\$ 161.25	141.87	0.81	0.71	(19.38)	-12.02%
250	\$ 198.29	165.72	0.79	0.66	(32.57)	-16.43%
300	\$ 235.32	189.56	0.78	0.63	(45.76)	-19.45%
350	\$ 272.37	213.40	0.78	0.61	(58.97)	-21.65%
400	\$ 309.40	237.25	0.77	0.59	(72.15)	-23.32%
450	\$ 346.44	261.10	0.77	0.58	(85.34)	-24.63%
500	\$ 383.47	284.94	0.77	0.57	(98.53)	-25.69%
600	\$ 457.55	332.63	0.76	0.55	(124.92)	-27.30%
700	\$ 531.62	380.32	0.76	0.54	(151.30)	-28.46%
800	\$ 605.70	428.01	0.76	0.54	(177.69)	-29.34%
900	\$ 679.77	475.70	0.76	0.53	(204.07)	-30.02%
1000	\$ 753.85	523.39	0.75	0.52	(230.46)	-30.57%
1500	\$ 1,124.21	761.84	0.75	0.51	(362.37)	-32.23%

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

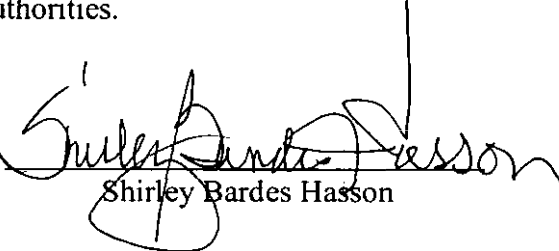
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Shirley Bardes Hasson, being Manager, Regulatory Policy of Columbia Gas of Pennsylvania, Inc. ("Columbia"), hereby state that the testimony set forth in Columbia Statement Nos. 16 and 116-R are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit No. SBH-1, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Shirley Bardes Hasson

2-13-13

Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R- 2012-2321748

**DIRECT TESTIMONY OF
SHIRLEY BARDES HASSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

1 Q. Please state your name and business address.

2 A. Shirley Bardes Hasson, 121 Champion Way, Suite 100, Canonsburg,
3 Pennsylvania.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the
6 Company") as Manager, Regulatory Policy.

7 Q. What are your responsibilities as Manager, Regulatory Policy?

8 A. I am responsible for managing regulatory activity before the Pennsylvania Public
9 Utility Commission ("Commission"). This responsibility includes ensuring
10 timely, accurate regulatory filings before the Commission as well as tariff
11 interpretation for compliance purposes. I also monitor cases before the
12 Commission and recommend Company participation when warranted.

13 Q. What is your professional experience?

14 A. I have been an employee of Columbia since 1987 when I accepted a position in the
15 Company's customer service department. In 1989, I was promoted to Office
16 Operations Training Instructor where I provided customer service and compliance
17 training to telephone representatives and field service technicians. My customer
18 service and training experience required comprehensive knowledge of Chapter 56
19 and Columbia's tariff. From 1995 until 2003, I held various positions working with
20

1 CHOICE¹ and large commercial and industrial transportation, at first as a
2 Distribution Gas Transportation Coordinator and progressing to Manager, Gas
3 Transportation in 2001. I was intimately involved in the original development,
4 expansion, and modification of the Columbia CHOICE program. I supervised
5 employees who provided billing, collections and customer service to Columbia's
6 largest commercial and industrial distribution service customers, and I acted as
7 liaison between the Natural Gas Suppliers and the Company. In 2004, I joined the
8 Regulatory Department as Manager, Regulatory Policy.

9 Q. Have you testified before this or any other Commission?

10 A. Yes, I have provided testimony before this Commission in several customer formal
11 complaint cases and in Columbia's last two base rate cases at Docket Nos. R-2009-
12 2149262 and R-2010-2215623. I have also testified before the Maryland Public
13 Service Commission on several occasions.

14 Q. What is the purpose of your testimony in this case?

15 A. My purpose in this proceeding is to present and sponsor Columbia's requested tariff
16 changes.

17 Q. What exhibits are you sponsoring?

18 A. I am sponsoring Exhibit No. 14 Schedule 1 – the list of reports, data or statements
19 requested by and submitted to the Commission and Exhibits 14 and
20

¹ Customer CHOICESM is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Pennsylvania, Inc. Choice[®] is a registered mark of Columbia Gas of Ohio, Inc. and its use has also been licensed by Columbia Gas of Pennsylvania, Inc.

1 114 Schedule 2, which are copies of present tariff pages and the Company's
2 proposed changes to those tariff pages.

3 Q. Explain the scope of your testimony in this proceeding.

4 A. I will provide a summary explanation of the proposed changes contained in
5 Supplement No. 190 to Columbia's Tariff Gas - Pa. PUC No. 9.

6 Q. Please provide an overview of the changes that the Company is proposing to its
7 tariff.

8 A. The Company's substantive proposals include: 1) two corrections to the
9 Description of Territory section of the tariff; 2) changes to the rates for
10 Distribution Charges, Customer Charges and Riders, and changes to the annual
11 consumption eligibility for Commercial and Industrial rate schedules as detailed
12 on Tariff Page Nos. 16 through 21; 3) a name change to the fixed charge currently
13 referred to as the "Customer Charge"; 4) the addition of a "Pass-through Charge"
14 that will consist of previously approved Riders currently included in the
15 Distribution Charge on the customer bill and newly proposed Riders and rates; 5)
16 the revision of Price-to-Compare in the tariff; 6) the addition of the Gas
17 Procurement Charge Rider; 7) the addition of a new Rider referred to as the
18 Merchant Function Charge. 8) the addition of the Revenue Normalization
19 Adjustment Rider; and 9) the new Pilot Rider New Area Service. Additionally,
20 there are non-substantive formatting and grammatical changes throughout the

1 tariff. A comprehensive list of changes being proposed is attached to this
2 testimony as Exhibit SBH-1 and on Tariff Page Nos. 2 through 2e.

3 **1. DESCRIPTION OF TERRITORY**

4 Q. What two corrections were made to the Description of Territory section of the
5 tariff?

6 A. When reviewing the Description of Territory, Columbia found two errors: 1)
7 Potter Township was misspelled as "Patter" Township, and 2) Harris Township
8 had never been added to the tariff. Both these corrections appear under Centre
9 County on Page No. 7 of the tariff.

10 Q. What leads Columbia to believe these two items were errors in the tariff?

11 A. Columbia found in its records an order from the Pennsylvania Public Utility
12 Commission dated May 9, 1966. That order approves Columbia's application at
13 A. 92869 to serve parts of Centre County, including Harris Township and Potter
14 Township and the application of Central Pennsylvania Gas Company requesting
15 to abandon service to those same townships at A. 93024.

16 **2. RATE & QUANTITY BREAK CHANGES**

17 Q. Explain the changes to Tariff Page Nos. 16 through 21.

18 A. Tariff Page Nos. 16 through 21 reflect changes to the Distribution Charges,
19 Customer Charges and eligibility for rate schedules supported by the rate design
20 testimony in Columbia Statement No. 15 sponsored by Witness Strauss. Please
21 refer to Columbia Statement No. 15 for detailed information regarding the

1 proposed changes to rates and usage-based eligibility. Pages 16 through 20
2 reflect a "Pass-through Charge" and a Revenue Normalization Adjustment
3 column appears on Pages 16 and 18. Both these items are discussed later in my
4 testimony. Pages 16 through 21 have been reformatted so that a customer can
5 match the rates on their bill to the rates on these pages.

6 Q. What is the purpose of new tariff pages 21a, 21b and 21c?

7 A. Tariff Pages 21a, 21b and 21c have been added to the tariff to clarify the
8 components of the Gas Supply Charge, the newly proposed Pass-through Charge
9 and the Price-to-Compare.

10 Q. Please explain Tariff Page 21a.

11 A. Newly proposed Tariff Page 21a is a summary of the components that make up
12 the Gas Supply Charge for customers purchasing gas from the Company on Rate
13 RSS, Rate RDGSS, Rate SGSS, Rate LGSS or Rate MLSS.

14 Q. What do Tariff Pages 21b and 21c include?

15 A. Tariff Pages 21b and 21c reflect a summary for the Pass-through Charge
16 components and the Price-to-Compare components, respectively. These charges
17 are discussed in detail later in my testimony.

18 **3. CUSTOMER CHARGE TO SYSTEM CHARGE**

19 Q. Is Columbia proposing to change the name of the fixed charge currently referred
20 to as the "Customer Charge"?

1 A. Yes. Columbia proposes to change the name of the fixed charge that appears on
2 customer bills from "Customer Charge" to "System Charge".

3 Q. What is the reason for making this change?

4 A. While the Company has used the term "Customer Charge" internally to refer to
5 the fixed revenue to be recovered from each individual customer, that term is not
6 a true description of what the fixed charge represents to the Customer. Columbia
7 is not charging a customer for being a customer. Instead the fixed charge is to
8 recover some of the costs to maintain the safety and reliability of Columbia's
9 distribution system and for meter reading and billing. The phrase "System
10 Charge" more accurately describes what the fixed charge represents.

4. PASS-THROUGH CHARGES

12 Q. Pages 16 through 20 of the proposed tariff reflect a "Pass-through Charge".
13 Please explain.

14 A. Columbia is proposing a new line item be added to the customer bill and labeled
15 "Pass-through Charge".

16 Q. What is the reason for the new Pass-through Charge?

17 A. As mentioned in witness Strauss's testimony in Statement No. 15, one of the
18 principles established for the proposed rate design is simplicity. That principle
19 carries over to the changes proposed for the tariff and the customer bill.
20 Columbia believes the Pass-through Charge line item will provide customers a
21 more transparent reflection of the rates they are charged on their Columbia bill.

1 Q. Please explain in detail.

2 A. Today, it is simply impossible for a customer to identify the base rate within the
3 Distribution Charge that appears on a customer's bill. In fact, up to thirty-eight
4 percent (38%) of the current distribution charge reflects costs that are passed
5 through to customers that are not related and make no contribution to the
6 distribution and billing services provided by Columbia. Currently, the
7 Distribution Charge line item on a customer bill includes the following
8 components where applicable: 1) the base distribution rate; 2) the Purchased Gas
9 Demand Cost ("PGDC") charge; 3) the PGDC "E" Factor; 4) the Customer Choice
10 Rider ("Rider CC"); 5) the Capacity Assignment Factor; and 6) the Universal
11 Service Plan Rider ("Rider USP").

12
13 Since 2008 when Columbia began filing frequent base rate cases with the
14 Pennsylvania Public Utility Commission, it has become increasingly evident that
15 customers have difficulty understanding utility rates, and specifically what
16 charges contribute to the Company's ability to provide safe, reliable service, gas
17 meter maintenance, and accurate billing, and what charges are gas costs or
18 riders. The bill is unnecessarily difficult to understand in its current form
19 because the line item labeled "Distribution Charge" contains charges that are not
20 in fact distribution related, but were added to that line item because they are
21 usage-based charges. Contributing to that difficulty is the quarterly change to the

1 line item labeled "Distribution Charge" as a result of the quarterly change to the
2 PGDC and Rider USP, and the annual change to the PGDC "E" Factor. For
3 simplicity, the Distribution Charge should just reflect the distribution charge
4 specified in the tariff and it should only change after a base rate change is
5 implemented. Columbia believes that the rates that appear on a customer bill
6 will be easier to understand for regulators, legislators, media, Natural Gas
7 Suppliers and customers if the components of the current Distribution Charge
8 that change outside of a base rate case are identified separately on the customer
9 bill in a line item labeled "Pass-through Charge".

10 Q. What are the components of the Pass-through Charge?

11 A. The components of the Pass-through Charge are: 1) the PGDC; 2) the PGDC "E"
12 Factor; 3) the Rider CC; 4) the Rider USP, and, for Choice Distribution Service
13 customers served under Rate CAP, Rate RDS, Rate RDGDS or Rate SCD, 5) the
14 credit of the Capacity Assignment Factor.

15 Q. What is the significance of the label "Pass-through Charge"?

16 A. The PGDC, the PGDC "E" Factor, the Capacity Assignment Factor and the Rider
17 CC all represent pipeline capacity costs that Columbia receives and is authorized
18 to pass on to customers dollar-for-dollar. Likewise, Columbia does not earn a
19 return on the costs billed to residential customers through the Rider USP. Each
20 of these components are therefore "passed through" to customers. Therefore the

1 label "Pass-through Charge" is an appropriate label for these costs and simplifies
2 the explanation of charges on a customer's bill.

3 Q. What will remain in the Distribution Charge line item on the customer bill?

4 A. Only Columbia's approved base rate will remain in the Distribution Charge.
5 Customers will only see the rate on this line item change when a base rate case
6 filing, approved by the Commission, goes into effect.

7 Q. How often will the Pass-through Charge rate change?

8 A. The Pass-through Charge rate will change quarterly as a result of the PGDC and
9 the Rider USP quarterly changes. In the quarterly filing that becomes effective
10 October 1st each year, the PGDC "E" Factor may also change in compliance with
11 the most recent 1307(f) order.

12 Q. List all the line items a customer may see on their bill if the Commission approves
13 Columbia's request for a Pass-through Charge.

14 A. The line items a customer may see in the Detail of Charges section of their bill
15 are:

16 System Charge

17 Gas Supply Charge (where applicable)

18 Gas Cost Adjustment (where applicable)

19 Distribution Charge

20 Revenue Normalization Adjustment

21 Pass-through Charge (where applicable)

1 State Tax Adjustment Surcharge

2 Q. If the Pass-through Charge was on a customer bill today, what would the Pass-
3 through Charge rate and the Distribution Charge rate be?

4 A. The rate that will appear in the Pass-through Charge line will depend on the
5 customer's current rate schedule. If the Pass-through Charge were in place
6 today, a residential customer who is purchasing gas from Columbia would see a
7 Pass-through Charge of \$0.16361² per thm and a Distribution Charge of
8 \$0.26708 per thm for usage in excess of 21 therms.

9 Q. Is there anything else you want to mention regarding the Pass-through Charge?

10 A. Yes. In order to make the components of the Pass-through Charge more
11 transparent and understandable, Columbia has added Page No. 21b to its tariff.
12 Tariff Page No. 21b reflects the component breakdown and applicability of the
13 Pass-through Charge for each Rate Schedule eligible to receive at least one of the
14 Pass-through Charge components.

15 **5. PRICE-TO-COMPARE**

16 Q. What change to Columbia's tariff is a result of the Commission's new regulations
17 regarding the "Price-to-Compare"?

18 A. As a result of new regulations promulgated in Docket No. L-2008-2069114, the
19 Price-to-Compare ("PTC") calculation will now include two additional

² Based on rates in effect on September 28, 2012.

1 components: 1) the new Gas Procurement Charge (“GPC”) and the Gas Cost
2 Adjustment.

3 Q. What other components make up the PTC?

4 A. The components included in the PTC will be the Purchased Gas Commodity Cost,
5 the Gas Cost Adjustment or PGCC “E” Factor, the Capacity Assignment Factor,
6 the GPC and the Merchant Function Charge (“MFC”).

7 Q. Does the summary of the PTC appear in the proposed tariff?

8 A. Yes, Page No. 21c reflects a summary of the components that make up the PTC.

9 Q. Will the PTC appear on a customer’s bill?

10 A. Yes, Columbia intends to include the PTC as a bill message on residential and
11 small commercial customer bills.

12 Q. How does the PTC compare to the Gas Supply Charge billed to residential and
13 small commercial sales service customers?

14 A. The PTC includes two components not included in the Gas Supply Charge. Those
15 two components are the Gas Cost Adjustment and the Capacity Assignment
16 Factor.

17 Q. Why is the Gas Cost Adjustment not included in the Gas Supply Cost?

18 A. The Gas Cost Adjustment is required to appear as a separate line item on a
19 customer’s bill³.

20 Q. Why is the Capacity Assignment Factor not in the Gas Supply Cost?

³ PA Code Title 52, Chapter 62, §62.74

1 A. The Capacity Assignment Factor is a part of purchased gas demand costs that are
2 reflected in the Pass-through Charge. The Factor is included in the PTC as it
3 reflects demand costs that Choice customers do not pay to Columbia as a result of
4 the Choice Natural Gas Suppliers being assigned firm capacity by Columbia.

5 **6. GAS PROCUREMENT CHARGE**

6 Q. Columbia's tariff changes reflect a Rider GPC – Gas Procurement Charge. What
7 is this new Rider?

8 A. The Rider GPC on tariff Page No. 160 is a direct result of new regulations in the
9 Pa. Code, Title 52, Chapter 62, §62.223.

10 Q. What is the purpose of this Rider?

11 A. The Rider was created to remove the gas procurement costs from base rates and
12 add them to the PTC.

13 Q. Please explain the detail behind the calculation of the Rider GPC.

14 A. Witness Strauss, in Statement No. 15, describes in detail the calculation of the
15 Rider GPC.

16 Q. Where is the Rider GPC included in the customer's bill?

17 A. The GPC charge is a component of the Gas Supply Charge.

18 **7. MERCHANT FUNCTION CHARGE**

19 Q. Would you please explain Columbia's proposal for the new "Rider MFC –
20 Merchant Function Charge"?

1 A. Tariff Page No. 161 reflects a new Rider referred to as the "Merchant Function
2 Charge" ("Rider MFC"). This Rider is included in the tariff in compliance with
3 the Final Rulemaking Order in Docket No. L-2008-2069114.

4 Q. What is the purpose of Rider MFC?

5 A. The Rider MFC is a component of the PTC and reflects the cost of uncollectibles
6 associated with the natural gas supply sold by Columbia to customers through the
7 Sales Service Rate Schedules.

8 Q. How is the Merchant Function Charge calculated?

9 A. The Merchant Function Charge equals the Purchased Commodity Cost of Gas
10 multiplied by the uncollectible expense ratio filed in this rate case. The resulting
11 rate is included in the Gas Supply Charge and thus the PTC. The uncollectible
12 percentage is specified in Rider MFC on Tariff Page No. 161.

13 Q. How often does the percentage change?

14 A. The Rider MFC percentage changes each time new base rates become effective
15 after a base rate case.

16 Q. How often does the Rider MFC rate change?

17 A. The Rider MFC rate changes every quarter when the MFC percentage is applied
18 to the purchased gas commodity cost filed in the quarterly Purchased Gas
19 Adjustment filing.

20 Q. Is the Merchant Function Charge a new charge for Columbia Sales Service
21 customers?

1 A. No. Columbia has been including the cost of uncollectibles in its Gas Supply
2 Charge to Sales Service customers since October 28, 2008 when the Settlement
3 approved by the Commission in Docket No. R-2008-2011621 went into effect.
4 The new regulation identifies this existing component as the Merchant Function
5 Charge and orders that a Rider be established in the tariff.

6 **8. REVENUE NORMALIZATION ADJUSTMENT RIDER**

7 Q. Witness Strauss's testimony at Statement No. 15 discusses a new Revenue
8 Normalization Adjustment Rider. Where does the Rider appear in the proposed
9 tariff?

10 A. The Rider RNA – Revenue Normalization Adjustment (RNA) appears on Tariff
Page Nos. 162 and 163.

12 Q. How will the Revenue Normalization Adjustment appear on the customer bill?

13 A. Please see Witness Strauss's testimony at Statement No. 15 for details regarding
14 the calculation and bill presentation of the RNA.

15 **9. PILOT RIDER NEW AREA SERVICE**

16 Q. Tariff Page No. 174 reflects "Pilot Rider NAS – New Area Service". What is this
17 Rider?

18 A. The Pilot Rider New Area Service ("Pilot Rider NAS") was created to provide
19 another option for interested applicants who would otherwise be required to pay
20 a deposit when a line extension is required to serve the applicant.

21 Q. Please describe the Pilot Rider NAS design.

1 A. Please see Witness Erich A. Evan's testimony at Statement No. 19 for details
2 surrounding the Pilot Rider NAS.

3 Q. Are there any other changes you want to mention?

4 A. Yes. There are non-substantive formatting and grammatical changes throughout
5 the tariff. A comprehensive list of changes being proposed is attached to this
6 testimony as Exhibit SBH-1 and on proposed Tariff Page Nos. 2 through 2f in
7 Exhibit 14, Schedule 2 of the base rate case filing at Docket No. R-2012-2321748.

8 Q. Does this conclude your direct testimony?

9 A. Yes.

LIST OF TARIFF CHANGES

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement #, Effective & Issue Date.
2-2f	List of Changes	List of Changes.
3	Table of Contents	Added the Gas Supply Charge Summary as Page 21a, the Pass-through Charge Summary as Page 21b and the Price-to-Compare Summary as Page 21c.
4	Table of Contents	Added the GPC, MFC and RNA Riders.
5	Table of Contents	Moved "2.5 Character of Distribution Service" from page 4.
7	Description of Territory	Added "Harris Township" and changed "Patter" to "Potter" under "Centre County".
11	Rates Available Under this Tariff	Changed "536,500 thm or greater" to "in excess of 540,000 thm" in Rate LDS. Changed "64,380" to "64,400" in Rate LGSS.
12	Rates Available Under this Tariff	Changed "of not less than 268,250 thm" to "in excess of 274,000 thm" in Rate MLDS and Rate MLSS.
13	Rates Available Under this Tariff	Changed "below 64,380 thm" to "less than 64,400 thm".
14	Rates Available Under this Tariff	Changed "64,380" to "64,400" in Rate SCD and Rate SDS. Changed "536,500" to "or equal to 540,000" in Rate SDS. Changed "6,438" to "in excess of 6,440" in Rate SDSS. Changed "Default (Other than Slamming) By the NGS" to "NGS Default" in Rate SDSS.
15	Rates Available Under this Tariff	Changed "64,380" to "or equal to 64,400" in Rate SGDS. Changed "64,380" to "or equal to 64,400" in Rate SGSS.
16	Rate Summary	Changed "Customer Charge" to "System Charge". Changed the Distribution Charge for Rate RSS & Rate SGSS. Added a "Revenue Normalization Adjustment" column and a "Pass-through Charge" column.
17	Rate Summary	Changed "Customer Charge" to "System Charge". Changed the Distribution Charge for Rate LGSS & Rate MLSS. Added a "Pass-through Charge" column.
18	Rate Summary	Changed "Customer Charge" to "System Charge". Changed the Distribution Charge for Rate RDS, Rate SCD, Rate SGDS and Rate SDS. Added a "Revenue Normalization Adjustment" column and a "Pass-through Charge" column.

LIST OF TARIFF CHANGES

Page	Page Description	Revision Description
19	Rate Summary	Changed "Customer Charge" to "System Charge". Changed the Distribution Charge for Rate LDS & Rate MLDS. Added a "Pass-through Charge" column.
20	Rate Summary	Changed "Customer Charge" to "System Charge". Changed the Distribution Charge for Rate RDGSS and Rate RDGDS. Added a "Revenue Normalization Adjustment" column and a "Pass-through Charge" column.
21	Riders and Other Rates Summary	Added Rider GPC, Rider MFC, Rider RNA, the Price-to-Compare and the STAS.
21a	Gas Supply Charge Summary	New page providing Gas Supply Charge detail.
21b	Pass-through Charge Summary	New page providing Pass-through Charge detail.
21c	Price-to-Compare Summary	New page providing Price-to-Compare detail.
23	The Gas Tariff	Added a definition for "Capacity Assignment Factor".
24	The Gas Tariff	Revised the definition of "Distribution Charge".
25	The Gas Tariff	Revised the definition of "Gas Cost Adjustment". Added a definition for "Gas Supply Charge" and "Pass-through Charge". Moved the definition of "Pipeline Scheduling Point" to page 26.
26	The Gas Tariff	Added the definition of "Pipeline Scheduling Point" from page 25. Added a definition of "Price-to-Compare". Moved the definition of "Shipper" to page 27.
27	The Gas Tariff	Added the definition of "Shipper" from page 26. Added a definition for "System Charge". Moved the definition of "User Without Contract" to page 28.
28	The Gas Tariff	Added the definition of "User Without Contract" from page 27.
45	6. Credit	Changed "Customer Charge" to "System Charge".
55	13. Service Continuity	Changed "Customer Charge" to "System Charge".
57	15. Measurement	Removed "17" from heading.
76	Rate RSS	Revised the "Rate" description. Revised the "Minimum Monthly Charge" to reflect "System Charge". Revised the "Rider PGC" to reflect "Pass-through Charge". Revised the "USP Costs and Customer Choice Costs" to reflect the "Pass-through Charge".

LIST OF TARIFF CHANGES

Page	Page Description	Revision Description
77	Rate RSS	Removed item 3 under "Special Provisions".
78	Rate RDS	Revised the "Rate" description. Changed "Customer Charge" to "System Charge" in the "Minimum Charge" description. Revised the "Rider PGC" description to reflect "Pass-through Charge". Revised the "USP Costs and Customer Choice Costs" to reflect the "Pass-through Charge".
79	Rate RDS	Deleted item 6 of "Special Provisions".
81	Rate RDGSS	Revised the "Rate" description.
82	Rate RDGSS	Revised the "Rider PGC" and the "Universal Service Plan and Customer Choice Costs" descriptions to reflect "Pass-through Charges". Revised the "Minimum Charge" description.
83	Rate RDGSS	Changed "monthly customer charge" to "System Charge".
84	Rate RDGDS	Revised the "Availability" and "Rate" descriptions.
85	Rate RDGDS	Revised the "Universal Plan and Customer Choice Costs" paragraph to reflect the "Pass-through Charge". Eliminated the "Applicable Sales Service Rate" paragraph. Changed "monthly customer" to "System" in the "Special Provisions".
86	Rate SGSS	Changed "64,380" to "64,400". Revised the "Rate", "Minimum Charge" and "Determination of System Charge" descriptions.
87	Rate SGSS	Revised the "Rider PGC" and the "Customer Choice Costs" paragraphs to reflect "Pass-through Charges". Added "Customer Development/Retention Provisions" items "b." and "c." from page 88 and changed "customer charge" to "System Charge".
88	Rate SGSS	Moved "Customer Development/Retention Provisions" items "b." and "c." to page 87. Changed "64,380" to "64,400" in item 4 of "Special Provisions".
89	Rate SGDS	Changed "64,380" to "64,400" in the "Availability" paragraph. Revised the "Rate" description.
90	Rate SGDS	Revised the "Rider PGC" and the "Customer Choice Costs" descriptions to reflect the "Pass-through Charge". Revised the "Determination of System Charge" and "Minimum Charge" paragraphs.
92	Rate SGDS	Revised the "Customer Development/Retention Provisions" description to reflect "Gas Cost Adjustment", "Gas Supply Charge", "Distribution Charge", "System Charge" and "Pass-through Charge". Changed "64,380" to "64,400" in the "Special Provisions".

LIST OF TARIFF CHANGES

Page	Page Description	Revision Description
93	Rate SCD	Changed "64,380" to "64,400" in the "Availability" paragraph. Revised the description in the "Rate" and "Minimum Charge" descriptions.
94	Rate SCD	Revised the "Customer Choice" and "Rider PGC" descriptions to reflect the "Pass-through Charge". Revised items 3 and 6 of the "Special Provisions".
96	Rate SDS	Revised the "Availability" description.
97	Rate SDS	Revised the "Rate" and "Minimum Charge" descriptions.
98	Rate SDS	Revised the "Applicable Sales Service Rate" description.
99	Rate SDS	Changed "536,500" to "in excess of 540,000" and "customer" to "System" in item 2 of the "Special Provisions".
100	Rate LGSS	Changed "64,380" to "64,400" in the "Availability" paragraph. Revised the "Rate" description. Revised the "Determination of System Charge" description.
101	Rate LGSS	Revised the "Rider PGC" paragraph to reflect the "Pass-through Charge". Revised the "Minimum Charge" paragraph.
102	Rate LGSS	Changed "64,380" to "or equal to 64,400" in item 3 of the "Special Provisions".
103	Rate LDS	Changed "536,500" to "are in excess of 540,000" and revised the description in the "Availability" description.
104	Rate LDS	Revised the "Rate" description.
105	Rate LDS	Revised the "Minimum Charge" description.
106	Rate LDS	Revised quantities and text in item 2 of "Special Provisions".
107	Rate MLSS	Revised the "Rate" description. Changed "of not less than 268,250" to "greater than 274,000" in the "Availability" description.
108	Rate MLSS	Revised the "Determination of System Charge" and "Minimum Charge" descriptions.
109	Rate MLSS	Revised the "Rider PGC" paragraph to reflect the "Pass-through Charge". Changed "268,250" to "or equal to 274,000".
111	Rate MLDS	Changed "of not less 268,250" to "greater than 274,000" in the "Availability" description.
112	Rate MLDS	Revised the "Rate", "Determination of System Charge" and "Minimum Charge" descriptions.
114	Rate MLDS	Changed "268,250" to "or equal to 274,000" in item 5.
116	Rate NCS	Changed "Distribution Rate" to "Distribution Charge". Changed "customer charge" to "System Charge".
118	Rate NSS	Changed "Customer Charge" to "System Charge" in the "Rates" description.
121	Rate NSS	Changed "below 64,380" to "less than or equal to 64,400".

LIST OF TARIFF CHANGES

Page	Page Description	Revision Description
122	Rate SDSS	Revised quantities and text in the "Availability" description. Revised the "Rate" and "Character of Service" descriptions.
123	Rate SDSS	Changed "6,438" to "6,440" in the "Special Provisions" paragraph.
125	Rate CDS	Revised the "Rate" description.
127	Rate GDS	Revised the "Rate" description.
130	Rate NGV	Changed "customer charge" to "System Charge" in the "Rate" description.
132	Rate PS	Revised the "Rate" description. Revised the "Rider PGC" and the "Customer Choice" paragraphs to reflect the "Pass-through Charge".
135	Rate SS	Revised the "Gas Supply Rate for Purchases" and "State Tax Adjustment Surcharge" descriptions.
137	Rate DGDS	Revised the "Rate" description..
139	Rate CAP	Revised page title.
140	Rate CAP	Revised page title.
141	Rate CAP	Revised page title.
142	Rate CAP	Revised page title.
143	Rate CAP	Revised page title. Revised the "Rider PGC" paragraph to reflect the "Pass-through Charge".
146	Rider USP	Changed "Program" to "Plan" and "CAP Rider" to "USP Rider". Revised the "Rate" description. Replaced "Income Qualified Energy Efficiency Program (IQEEP)" with "WarmWise Audits and Rebates program".
147	Rider USP	Replaced "Income Qualified Energy Efficiency Program" with "WarmWise Audits and Rebates program".
148	Rider CC	Labeled the "Applicability" paragraph and changed "64,380" to "or equal to 64,400". Revised the "Rate" description.
149	Rider EDS	Changed "not less than 64,380" to "greater than 64,400" in the "Availability" paragraph. Revised the "Rate" description.
151	Rider PGC	Revised page title. Revised the "Provisions for Recovery of Purchased Gas Costs" description. Added a "Presentation on Customer Bills" description. Moved "Computation of Purchased Gas Commodity Costs Per Therm" paragraph to page 152.

LIST OF TARIFF CHANGES

Page	Page Description	Page Revision
152	Rider PGC	Revised page title. Added paragraph "Computation of Purchased Gas Commodity Costs Per Therm" from page 151.
153	Rider PGC	Revised page title. Added "Rate PS" in "Computation of Purchased Gas Demand Costs Per Therm" description.
154	Rider PGC	Revised page title. Revised "Provision of Purchased Gas Demand Cost Credit Due to Customers Electing Choice Distribution Service – Capacity Assignment Factor (CAF)" paragraph.
155	Rider PGC	Revised page title. Added Rate PS to item (b) (1) in "Determination of Over/Undercollection of Gas Costs". Added Rate CDS, Rate GDS, Rate DGDS and Rate NCS to item (b) (2) in the "Demand "E" Factor" description.
156	Rider PGC	Revised page title. Revised the "Adjustment of "E" Factor Amounts" description.
160	Rider GPC	New tariff Rider as a result of the Final Rulemaking Order in Docket No. L-2008-2069114.
161	Rider MFC	New tariff Rider as a result of the Final Rulemaking Order in Docket No. L-2008-2069114.
162	Rider RNA	New - Rider Revenue Normalization Adjustment.
163	Rider RNA	New - Rider Revenue Normalization Adjustment.
166	Rider EBS	Changed options from "three" to "two" in "Availability" description. Deleted "equal to or" and changed "536,500" to "540,000" in the "Option 1: Bank Tolerance" description. Changed "536,500" to "or equal to 540,000" in item 2 of "Option 1: Bank Tolerance" paragraph.
174	Rider NAS	New - Rider New Area Service.
175	Rider NAS	New - Rider New Area Service.
176	Rider NAS	New - Rider New Area Service.
193	RADS	Changed title of paragraph 2.14 to "NGS Default". Added paragraph "2.16 Special Services".
209	RADS	Removed paragraph 3.11.3 and renumbered subsequent paragraphs.
211	RADS	Changed "536,500" to "540,000" in the "Flow Order Management Service" description.
247	RADS	Removed the reference to the administrative adder in paragraph 4.13.4.5.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

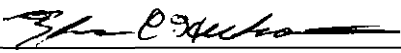
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Thomas C. Heckathorn, being Director of Transportation and Supplier Services of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 17, 117-R and 117-SR is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. TCH-1R through TCH-3R and TCH-117-SR, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Thomas C. Heckathorn

2-13-13
Hbg 87

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
THOMAS C. HECKATHORN
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

1 Q. Please state your name and business address.

2 A. Thomas C. Heckathorn, 200 Civic Center Drive, Columbus, Ohio 43215.

3 Q. By whom are you employed and in what capacity?

4 A. I am employed by NiSource Corporate Services Company as Director of
5 Transportation and Supplier Services.

6 Q. What are your responsibilities as Director of Transportation and Supplier Services?

7 A. I am responsible for administering the Customer CHOICESM programs and the
8 Distribution Service programs for six NiSource Inc. gas distribution companies,
9 which include Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc.,
10 Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., Columbia Gas of
11 Virginia, Inc. and Columbia Gas of Massachusetts. I am also responsible for
12 managing the capacity assets of these subsidiaries, which includes the scheduling of
13 system supply volumes on various pipelines and releasing pipeline capacity on a
14 market basis, as required under the Customer CHOICESM programs and associated
15 asset management arrangements. In addition, I have responsibility for confirming
16 delivered supplies at the city gate, reconciliation and payment of pipeline and
17 supplier invoices, and the generation of invoices related to the off system sales
18 programs.

19 Q. What is your educational and professional background?

20 A. I graduated from Northern Arizona University in 1980 with a Bachelor of Science
21 degree in Civil Engineering.

1 Q. Please briefly describe your professional experience.

2 A. I have over 30 years of experience in the natural gas industry. In 1981, I
3 commenced employment with Texas Eastern Transmission, LP as an Engineer in
4 the Gas Engineering Department. From 1981 to 1989 I held a variety of positions of
5 increasing responsibility at Texas Eastern in the Gas Engineering, Transportation
6 and Exchange, and System Control Departments. In 1989, I joined Columbia Gas
7 Transmission, LLC as Manager, Gas Transportation and Exchange where my
8 responsibilities included scheduling gas supplies and the negotiation and
9 administration of transportation and exchange agreements on third party pipelines.
10 In 1992, I accepted the position of Manager, Gas Contracts and Scheduling with the
11 Columbia Gas Distribution Companies (Columbia Gas of Kentucky, Inc., Columbia
12 Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania,
13 Inc., and Columbia Gas of Virginia, Inc.) where I was responsible for the scheduling
14 of gas supplies on interstate pipelines for the five Columbia distribution companies,
15 administration of gas purchase contracts, negotiation and administration of base
16 contracts for sale and purchase of natural gas, negotiation and administration of
17 gas transportation and storage agreements as well as miscellaneous agreements
18 associated with the gas supply function, and the implementation and the ongoing
19 development of the capacity release programs for the distribution companies. In
20 2010, I was promoted to my current position of Director, Transportation and
21 Supplier Services with the responsibilities previously described.

1 Q. Have you testified before this or any other Commission?

2 A. No, I have not.

3 Q. Please describe the scope of your testimony in this proceeding?

4 A. My testimony addresses two proposals relative to natural gas supplier issues and
5 presents the exhibits I am sponsoring in this proceeding.

6 Q. Please identify Columbia's proposals.

7 A. Based upon discussions with representatives of the natural gas supplier parties
8 from Columbia's last base rate case (Docket No. R-2010-2215623), Columbia
9 agreed to propose to: 1) provide a date and time stamp confirmation for every file
10 submitted by natural gas suppliers, and 2) provide for the daily processing of
11 customer rate code changes.

12 Q. Please explain each of these proposals and the reasons why Columbia agreed to
13 propose them in this proceeding.

14 A. Both of these proposals were the result of discussions between Columbia and the
15 natural gas supplier parties. The first proposal was requested by the natural gas
16 suppliers because they desire an electronic acknowledgement of receipt whenever
17 they submit a file electronically to Columbia. Upon review of this request, Columbia
18 considered it a reasonable request and is willing to accommodate the suppliers in
19 this regard. The second proposal resulted from the natural gas suppliers' concern
20 with the amount of time required for Columbia to process rate code changes for the
21 suppliers' customers. Columbia's second proposal provides suppliers with the

1 ability to submit customer rate changes daily. Those rate changes would then
2 become effective on the respective customer's next bill. Columbia proposed this
3 accelerated timeline to the natural gas suppliers in its discussions with the
4 suppliers and agreed to propose this change in its next base rate case (this case).
5 There are no tariff modifications required to implement these modifications.

6 Q. What exhibits are you sponsoring?

7 A. The table below lists the exhibits that I am sponsoring as well as providing a brief
8 description of each.
9

Exhibit No.	Description
Exhibit 10, Schedule 3(22), Page 1	Supporting data detailing curtailment adjustments, procedures and policies.
Exhibit 10, Schedule 4(39), Page 27	Procedures to govern relationships between respondent and potential customers
Exhibit 10, Schedule 5(4), Page 1	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.-Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification.
Exhibit 12, Schedule 1 (5), Page 1	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit 12, Schedule 4(24), Page 1	Purchased gas for test year and prior year,
Exhibit 12, Schedule 4(26), Page 1	Bulk transmission service costs
Exhibit 12, Schedule 4(30), Page 1	Purchased gas detail

Exhibit 12, Schedule 4(36), Page 1	Amounts of gas obtained through various suppliers
Exhibit 13, Schedule 6(27), Page 1	Schedule of Gas Producing Units Retired or Scheduled for Retirement
Exhibit 15, Schedule 2(2), Page 1	Overall System Map
Exhibit 15, Schedule 2(8), Page 1	Map of Gas System Facilities and Gas Service Areas
Exhibit 17, Page 1(1)	Description of All Property; Gas Supply; Service Agreements
Exhibit 17, Page 1(28)	Details of Firm Gas--Affiliated and Non-Affiliated Utilities
Exhibit 110, Schedule 3(22), Page 1	Supporting data detailing curtailment adjustments, procedures and policies.
Exhibit 110, Schedule 4(39), Page 27	Procedures to govern relationships between respondent and potential customers
Exhibit 110, Schedule 5(4), Page 1	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.-Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification.
Exhibit 112, Schedule 1(5), Page 1	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit 112, Schedule 2(23), Page 2	Fuel cost in excess of base compared to fuel cost recovery
Exhibit 112, Schedule 2(24), Page 2	Purchased gas for test year and prior year,
Exhibit 112, Schedule 2(25), Page 2	Energy cost and operating ratio used to determine increase in costs to serve additional load.
Exhibit 112, Schedule 2(26), Page 2	Bulk transmission service costs
Exhibit 112, Schedule 2(30), Page 2	Purchased gas detail
Exhibit 112, Schedule 2(31), Page 2	Fuel costs included in the base cost of fuel

Exhibit 112, Schedule 2(36), Page 2	Amounts of gas obtained through various suppliers
Exhibit 112, Schedule 2(11), Page 2	Net Fuel Clause Adjustment by month for the test year
Exhibit 113, Schedule 4, Page 1(27)	Schedule of Gas Producing Units Retired or Scheduled for Retirement
Exhibit 115, Page 1(2)	Overall System Map
Exhibit 117, Page 1(1)	Description of All Property; Gas Supply; Service Agreements
Exhibit 117, Page 1(28)	Details of Firm Gas--Affiliated and Non-Affiliated Utilities

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2 Q. Does this complete your Prepared Direct Testimony?

3 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

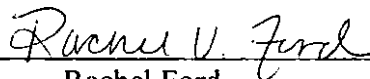
Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Rachel Ford, being Director of Communications and Community Relations of Columbia Gas of Pennsylvania, Inc. ("Columbia"), hereby state that the testimony set forth in Columbia Statement Nos. 18 and 118-R are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. RF-1 and RVF1-R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013


Rachel Ford

2-13-13
Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No.R-2012-2321748

**DIRECT TESTIMONY OF
RACHEL FORD
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Rachel Ford. My business address is 121 Champion Way, Suite 100,
3 Canonsburg, PA 15317.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the
6 Company") as Director of Communications and Community Relations.

7 Q. Please briefly describe your professional experience.

8 A. From June 2005 through October 2009, I held a variety of external public relations
9 roles with Government Employees Insurance Company ("GEICO") based in
10 Washington, D.C. In October 2009, I joined Columbia's Communications
11 Department. Since joining the Company I have held various communications
12 positions each with increasing responsibilities including Communications and
13 Community Relations Specialist, Communications and Community Relations
14 Manager, and my current role as Director.

15 Q. Please describe your educational background.

16 A. In 2005, I graduated Cum Laude with a Bachelor of Arts degree in advertising and
17 public relations and a minor in business from the Pennsylvania State University.

18 Q. What are your responsibilities in your current position?

19 A. I am responsible for managing Columbia's Communications Department, which
20 develops and executes community relations, media relations, internal
21 communications, customer communications, public awareness, gas safety,
22 advertising and web management initiatives for Columbia. An important aspect of
23 our departmental role is to manage customer communications related to activities

including natural gas safety, "Call Before You Dig," infrastructure upgrade projects, energy efficiency programs, customer assistance programs, regulatory filings, and community activities.

Q. Have you previously testified before this or any other regulatory agency?

A. No, I have not.

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

A. The purpose of my testimony is to present and describe the new customer education program "Count On Columbia" ("Program" or "Count On Columbia") that Columbia is proposing in this case relative to the positive benefits of the Company's infrastructure replacement program will have on natural gas safety, affected communities and the economy. In addition, damage by third-party excavators is still the number one risk on Columbia's system. I will support Columbia's proposal to increase its annual public education program required by Federal Regulations and consistent with the American Petroleum Institute's ("API") Recommended Practice ("RP") 1162 spend that will target excavators and educate school children.

Q. Why is Columbia proposing Count on Columbia?

A. Prior to initiating an aggressive infrastructure replacement program in 2007, Columbia had not filed a base rate case since 1995. During that time, the Company's customers may have developed an inaccurate idea of the actual cost of providing safe, reliable and efficient natural gas service.

As noted above, the goal of Count on Columbia is to drive awareness and education among Columbia's consumers of the positive impact that the Company's

1 infrastructure replacement program has had on natural gas safety, the
2 communities we serve and the economy. The proposed Program will not only
3 expand upon current outreach efforts including community sponsorships, media
4 relations and infrastructure replacement customer communications, but also
5 dovetail with Columbia's annual RP 1162 public awareness campaign. The increase
6 in the Company's RP 1162 spend will also allow for increased outreach to
7 excavators and allow the Company to provide important information to school
8 children regarding natural gas safety and Call Before You Dig.

9 Q. Please describe the residential rate impact of the Company's rate case filings since
10 2007.

11 A. Columbia sought rate relief in 2008 after officially launching its infrastructure
12 replacement program then known as "New Tube." The parties to Columbia's 2008
13 base rate proceeding settled that case with a revenue increase of \$41.5 million,
14 resulting in an average total residential bill increase of 6.4 percent. Subsequently,
15 the Company has continued to seek rate relief to support its ongoing investment in
16 its natural gas distribution system, amounting to approximately \$190 million from
17 2009 to 2011. When including infrastructure investments made in 2012, Columbia
18 is on track to spend more than \$300 million to replace and upgrade its natural gas
19 delivery system from 2009 – 2012. The Company settled its 2010 base rate case
20 with an overall revenue increase of \$12 million, which increased the total average
21 residential bill by 2.58 percent. The Company also settled many issues in its 2011
22 base rate case including an overall revenue increase of \$17 million, which increased
23 the total average residential bill by 3.2 percent. Even with these somewhat frequent

base rate filings, it is important to note that when adjusted for inflation, the total average residential customer bill is currently about 25 percent lower than it was in 1991.

Q. Why is Columbia proposing the Program now?

A. There are several reasons why Columbia plans to implement an enhanced customer education program. First, Columbia is now filing its fourth rate case in five years as it invests over \$100 million to replace infrastructure in 2012 alone. The Company is sensitive to the impact that its infrastructure replacement and regulatory initiatives can have on its customers' economic situations and recognizes that its customers need to understand the reasons behind the Company's filings. Columbia believes that it should take a proactive approach to educate its customers of the direct and ancillary benefits of the Company's infrastructure replacement program including both economic and natural gas safety benefits.

Second, the Pennsylvania Public Utility Commission ("Commission") adopted a final policy statement on December 15, 2011 intended to improve utility communication with customers through the use of social media and other new technology. While the Commission's statement was focused on improving communications during public outages, the Commission's desire for utilities to better communicate with their customers can apply to more than just service interruptions. Count on Columbia is intended to help strengthen Columbia's customers' understanding of the Company's positive impact on both their personal lives and their communities, and will help Columbia to maintain an open and

1 trustworthy relationship with its customers.

2 Third, there is a lot going on in the energy industry in Pennsylvania, particularly
3 with the growth of the Marcellus Shale play. Columbia is not the only organization
4 in the industry that is focused on customer education. For example, the Marcellus
5 Shale Coalition announced two new staff members on August 15, 2010, whose sole
6 purpose is to focus on public education. Columbia needs to be a part of the public
7 conversation to help the customer understand exactly what services the Company
8 provides as well as distinguish its role from the other players in the energy
9 environment. Pennsylvania's, and the country's, focus on natural gas drilling can
10 cause some confusion for the general public, particularly around a distribution
11 company's role in getting gas from the pipeline company's city gate to the meter.

12 Columbia wants to ensure that its natural gas distribution customers understand
13 how Columbia's increased pipeline replacement efforts yield a direct benefit to
14 customers and communities, even though the replacements will result in rate
15 increases.

16 Q. Did Columbia rely on any research in developing Count on Columbia?

17 A. Yes, Columbia analyzed customer satisfaction studies produced by J.D. Power.

18 Q. What did Columbia learn from the research?

19 A. According to the 2011 J.D. Power survey results, Columbia's overall customer
20 communication satisfaction scores decreased from 2010 to 2011 by 10 percent.

21 While Columbia still ranked second in overall customer satisfaction and while the
22 communication satisfaction scores for the majority of Columbia's East Midsize
23 Segment peers also decreased, our goal is to improve our customer satisfaction

1 ratings. Some of the 2011 results demonstrate the need for a comprehensive
2 customer education program. Examples include:

- 3 • Only 31 percent of customers surveyed said they noticed any type of
4 communications from Columbia.
- 5 • Of those customers surveyed, the customers who retained messages about
6 company image (15 percent, 676 satisfaction ranking) and natural gas safety
7 (25 percent, 662 satisfaction rating) were more satisfied than those who
8 retained messages about their natural gas bills (54 percent, 618 satisfaction
9 ranking) and price rate changes (27 percent, 591 satisfaction ranking).

10 These statistics indicate that more of Columbia's customers are hearing the
11 message regarding changes to their natural gas bill but probably do not understand
12 the reasons and benefits behind those changes.

13 Q. Can you provide detail about the components of Count on Columbia?

14 A. Through Count on Columbia, the Company proposes to inform and educate its
15 customers about the positive impact that the infrastructure replacement program
16 has on natural gas safety, the communities it serves and the economy. Columbia
17 also will seek to educate customers that a necessary effect of such large scale
18 infrastructure replacement efforts will be rate increases. Promoting important
19 information to the public regarding safety, rate changes, community service and
20 economic impact is not only beneficial for the ratepayer's understanding of
21 Columbia's role, but critical to customer satisfaction.

22 As noted above, the proposed Program will not only expand upon current outreach
efforts, but also dovetail with Columbia's annual RP1162, or public awareness

1 campaign.

2 Q. What are Columbia's proposed outreach efforts?

3 A. The range of external media may include, but is not limited to, online information,
4 television, radio, print media, outdoor, direct marketing, bill inserts, media
5 relations, community events and sponsorships, online portal for children and
6 possibly social media.

7 Q. What is the cost of offering this Program?

8 A. Columbia proposes to set the initial annual budget at \$300,000. The \$300,000
9 will provide the Company with the means to explore a wide variety of media touch
10 points to reach a cross-section of natural gas consumers across varying
11 demographics. To put this budget into perspective, I note that the budget for
12 Columbia's 2001 Choice® customer education program was an average of
13 \$600,000 per year over three years. Like the Choice® program budget, Columbia
14 seeks to recover the budget for its customer education Program through rates.

15 Q. After evaluating the higher budgets for the Choice® customer education program,
16 do you believe \$300,000 is a sufficient budget amount?

17 A. For the initial program, yes. Columbia's Program is a comprehensive approach
18 utilizing a full range of media. The Company believes a modest start will allow the
19 program to remain manageable as it grows. An increase in the Program budget in

20 the future may be appropriate based on the results of the impact of the Program.

21 The Program as proposed introduces the efforts across the top markets to promote
22 consumer awareness about natural gas safety and the direct and supplementary
23 benefits of the company's infrastructure investment program. The approach is

built upon years of experience from past successful programs, like Choice®, and Columbia's more limited customer education promotions like its WarmWise: Audits and Rebates energy efficiency program. For detailed information including a cost breakdown about the proposed Program, please see Exhibit RF-1.

Q. Please explain Columbia's RP 1162 obligation for a public awareness program.

A. Pursuant to Federal Regulations, each pipeline operator must develop and implement a public education program that follows the guidance provided in the American Petroleum Institute's ("API's") Recommended Practice ("RP") 1162. The specific obligations of pipeline operators can be found at 49 C.F.R. § 192.616.

Q. Please provide more detail on what the Company is proposing in this case in respect to its RP 1162 program.

A. As noted in Company witness Kitchell's testimony (Columbia Statement No. 7), Columbia is proposing to increase its RP 1162 funding by \$200,000 on an annual basis. Over the last five years, Columbia has had a budget of \$127,500, \$100,645.10, \$103,700, \$89,250, and \$110,500, respectively, for compliance with RP 1162 in Pennsylvania. However, as discussed in detail in Mr. Cote's (Columbia Statement No. 8) and Mr. Kitchell's testimonies, damage by third-party excavators is still the number one risk on Columbia's system. Columbia proposes to increase its excavator outreach and excavator-targeted advertising in an effort to address this known cause for damage to its system. In addition, Columbia is proposing to add a children's component regarding third-party damage to educate school children on the importance of natural gas safety and Call Before You Dig using educational material, promotions, giveaways, special events and other

1 communication methods. The ultimate goal is to create youth "safety advocates"
2 who bring the message of gas safety awareness into their homes.

3 Q. With respect to an enhanced RP 1162 program, how will Columbia promote these
4 additional efforts to its customers?

5 A. Columbia will expand upon its current efforts to educate the affected public
6 including customers, excavators, contractors, local officials and emergency
7 responders. Currently, the Company uses community and event sponsorships,
8 radio and print advertising, bill inserts, excavator meetings, media relations and
9 direct mail to educate the affected public on the importance of call-before-you-dig.
10 If the enriched RP 1162 program proceeds as proposed, all current efforts will not
11 only be enhanced by both frequency of messaging and a broader distribution, but
12 additional modes of media may be introduced such as online and television
13 advertising, outdoor, an online portal for children and possible social media. In
14 addition, the development of the new children's component may use, but will not
15 be limited to, educational material, promotions, giveaways, and community events
16 and sponsorships.

17 Q. How did Columbia determine that \$200,000 is the appropriate amount to increase
18 its RP 1162 funding?

19 A. Columbia has spent an average of \$106,000 per year over the last 5 years to
20 educate the affected public on the importance of call-before-you-dig. While
21 current efforts sufficiently promote the safety program, as well as maintain
22 Columbia's compliance with Federal Regulations, more needs to be done. Despite
23 outreach efforts, in 2011 Columbia still experienced 53 occurrences of damage to its

1 system resulting from excavators failing to call 811. As referenced above, Company
2 witnesses Cote and Kitchell explain the ongoing risk that third-party damage
3 excavators still pose to Columbia's system. A more robust RP 1162 program that
4 addresses Columbia's number one system risk will support Columbia's efforts to
5 maintain safe and reliable service, decrease service interruptions and unnecessary
6 repair costs, and reduce the risk of a federally reportable incident (death, injury
7 requiring hospitalization and property damage over \$50,000) which, in turn, will
8 save money for customers, third-party offenders and the Company. With an
9 incremental increase of \$200,000 annually to the RP 1162 program, Columbia can
10 more than double current efforts to educate the affected public, and use additional
11 funding to develop and implement a brand-new children's program designed to
12 create youth "safety advocates," who can bring the message of gas safety awareness
13 into their homes and serve as future, safe natural gas distribution customers.

14 Q. If a change in rate design is approved in this case, is the Company prepared to
15 communicate this change to its customers?

16 A. Absolutely. Anytime there is a regulatory change that impacts customers or results
17 in a change to customers' bills, Columbia initiates an extensive education plan that
18 includes both internal and external communications pieces. For example, when
19 the Pennsylvania Public Utility Commission approved the modified rate design and
20 the conversion from Mcf to therm billing in the Company's 2011 base rate case,
21 there were a number of complicated issues to communicate to Columbia's
22 customers, including the allowance for the first 21 therms (or 2 Mcf) of distribution
charges to be included in the customer service charge. External customer

1 communications included multiple press releases, bill messages and inserts, an
2 online bill tutorial, a special information phone line, customer quarterly newsletter
3 articles, a customer information sheet available upon request, a special web page
4 that included frequently asked questions and key stakeholder letters and emails.
5 Internal communications pieces, designed to make sure all employees could easily
6 communicate with customers, included talking points, all-employee emails,
7 internal employee newsletter articles, copies of the customer bill inserts, special
8 informational 'visor cards' to keep in vehicles, intranet articles and special training
9 for customer service representatives.

10 Columbia is pleased to report that in 2011, despite some confusing rate changes,
11 only 22 of Columbia's 375,000 residential customers made either an informal or
12 formal complaint, and only 25 customers have made a complaint to date in 2012
13 regarding rate changes. That amounts to a complaint rate of less than 0.006% and
14 0.007% respectively. I attribute this to the Company's proven ability to
15 comprehensively communicate and educate both its employees and its customers
16 regarding complex regulatory issues.

17 Q. Does this conclude your testimony?

18 A. Yes.

19

Customer Education Program

Goals and Objectives

- Target adult Columbia customers.
- Drive awareness and education among Columbia's customers of the positive benefits that the company's infrastructure replacement program and subsequent base rate adjustments have on natural gas safety, affected communities and the economy.
- Program will not only expand upon current outreach and education efforts, but also dovetail with Columbia's annual RP1162, or public awareness, campaign.

Action Plan Components and Costs:*

- **Advertising: \$200,000**
 - Online
 - Television
 - Radio
 - Print
 - Outdoor
- **Direct Marketing/Print: \$50,000**
 - Bill inserts
 - Direct mail pieces
- **Public Relations: \$25,000**
 - Media relations
 - Community events and sponsorships
 - Social media
- **Digital: \$25,000**
 - Adult education
 - Education online portal

*All action plan components and cost allocations are proposed and subject to change. Any agency fees associated with a particular component will be including in the corresponding component final cost.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2012-2321748
	:		M-2012-2323645
Office of Consumer Advocate	:		C-2012-2330240
Office of Small Business Advocate	:		C-2012-2330539
Anastasia Stratigos	:		C-2012-2330724
Louis and Joanne Quahliero	:		C-2012-2332087
Angela Burnett	:		C-2012-2332497
G. Thomas Smeltzer	:		C-2012-2333247
Michelle Swartz	:		C-2012-2328788
Columbia Industrial Intervenors	:		C-2012-2334026
Johanna Shigle	:		C-2012-2336033
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

VERIFICATION

I, Erich A. Evans, being Director of Regulatory Strategy of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement Nos. 19 and 119-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein. I further state that I am responsible for Exhibit Nos. EAE-1 and EAE-1R, and that they are true and correct to the best of my knowledge, information and belief.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Erich A. Evans

2-13-13
Hbg R

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

vs.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2012-2321748

**DIRECT TESTIMONY OF
ERICH A. EVANS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

September 28, 2012

1 Q. Please state your name and business address.

2 A. My name is Erich Evans and my business address is 200 Civic Center Drive,
3 Columbus, Ohio.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by NiSource Corporate Services Company ("NCSC"), as Director
6 of Regulatory Strategy.

7 Q. What are your responsibilities as Director of Regulatory Strategy?

8 A. I am responsible for the research and development of strategy and programs for
9 the gas distribution segment of NiSource Inc., as well as research and study of gas
10 utility best practices.

11 Q. Please describe your professional experience and educational background.

12 A. I have been employed in various capacities with NCSC since 2003 in positions of
13 increasing responsibility. I started with the Company as Manager, Gas
14 Transportation and Sales support. In 2004 I was promoted to Director, Gas
15 Transportation and Sales Support; in 2006 I became the Director, Distribution
16 Customer Programs; in 2007 I became the Director, Commodity & Performance;
17 and in 2010 I assumed my current role as Director of Regulatory Strategy. Prior
18 to joining NCSC I held various positions with CSC Energy Services and Enron
19 Energy Services. I graduated from Miami University with a Bachelor's degree,
20 majoring in Economics. In addition, I have attended a variety of seminars on risk
21 management, project management, and finance sponsored by various trade
22 associations.

1 Q. Have you previously testified before the Pennsylvania Public Utility Commission
2 or any other state regulatory commissions?

3 A. Yes, I have submitted testimony before the Pennsylvania Public Utility
4 Commission and the Kentucky Public Service Commission.

5 Q. What is the scope of your testimony in this proceeding?

6 A. I am presenting and describing an optional rider that Columbia Gas of Pennsyl-
7 vania, Inc. ("Columbia" or "the Company") proposes to provide to its customers
8 for distribution line extensions. Specifically, my testimony presents a new pilot
9 rider that is designed to provide an additional option for customers who are re-
10 questing new gas distribution service from the Company in areas that do not
11 presently have gas distribution facilities.

12 Q. Can you describe the changes being made?

13 A. Columbia is proposing a pilot rider called "Pilot Rider NAS - New Area Service"
14 ("NAS"), a copy of which is attached to my testimony as Exhibit EAE-1. Pilot
15 Rider NAS will provide an alternative approach to paying the cost of facility ex-
16 tensions. Columbia's current procedure for any extension of Columbia's facilities
17 to serve new customers is to perform an economic analysis. If the full cost of the
18 extension cannot be justified by projected revenues, Columbia requests payment
19 of an up-front deposit for the amount greater than the maximum allowable in-
20 vestment (the "excess amount".) Pilot Rider NAS will allow all or a portion of
21 the excess amount to be recovered through an additional monthly charge payable
22 over a period of 20 years rather than a lump sum payment of the deposit. This

1 will significantly reduce the upfront cost of obtaining natural gas service from
2 Columbia where Columbia does not currently have facilities available.

3 Q. Why is Columbia making this change?

4 A. Columbia is making this change in an effort to make natural gas service more ac-
5 cessible to Pennsylvanians. In many cases, the economic analysis shows that a
6 large upfront payment is needed for Columbia to extend its facilities. This up-
7 front cost can deter customers from taking natural gas service. This is particular-
8 ly true when the customer is located a significant distance from Columbia's exist-
9 ing facilities. If it is an existing home where the owner is seeking natural gas ser-
10 vice, the deposit required from Columbia in addition to the cost of replacing
11 equipment can deter a homeowner from converting to natural gas service. Simi-
12 larly, when developers plan a new development, the deposit requirement could
13 cause them to decide against installing gas service to the homes or buildings.
14 Given the abundance of low-cost gas that is being produced in Pennsylvania as a
15 result of Marcellus Shale supplies, Columbia is committed to making it as easy as
16 possible for Pennsylvanians to obtain natural gas service.

17 Q. How long is Columbia proposing this Pilot remain in effect?

18 A. Columbia is proposing to implement the rider as a four year pilot. This will give
19 Columbia an opportunity to gauge its effectiveness and determine customer ac-
20 ceptance. However, any project established under Pilot Rider NAS will continue
21 for the full payment term.

22 Q. When will the pilot start?

1 A. The pilot will start the date that the Commission approves the rider as being ef-
2 fective.

3 Q. Who will be eligible for this pilot?

4 A. The pilot has been primarily designed to assist residential customers who are
5 seeking gas service. However, extension of facilities could also be made to com-
6 mercial and industrial customers as long as the project is primarily for residential
7 service. In this way a developer who is building a mixed use development would
8 be able to take advantage of Pilot Rider NAS. Likewise an existing school and
9 group of homes could also take advantage of Pilot Rider NAS.

10 Q. If it is a developer who brings the project to Columbia, who pays the monthly Pi-
11 lot Rider NAS surcharge?

12 A. The customer who moves into the development would pay the charge. The
13 charge will go with each meter that is set and whoever is receiving the monthly
14 bill for that meter will pay the Pilot Rider NAS surcharge on their monthly bill.

15 Q. Please describe in detail how this program will work.

16 A. Columbia's initial process for evaluating line extensions will remain unchanged.
17 When a customer contacts Columbia with a request for new service, Columbia
18 will evaluate the project exactly as it does today. The project will be reviewed and
19 the cost to extend Columbia's facilities will be determined. Next, Columbia pro-
20 jects the future revenue from the new customer(s). Columbia then subtracts the
21 net present value of the future revenue from the cost to extend the lines. If the
22 result is a positive number then no deposit is required. If the result is a negative

1 number, then a deposit is required. The amount of the deposit will be an amount
2 equal to bringing the equation to zero.

3 The customer will then have the option of paying the deposit, as they do today, or
4 Columbia can offer Pilot Rider NAS and the customer can have the payment cal-
5 culated over a 20 year period and a surcharge will be added to the monthly gas
6 bill. If the project involves more than one meter, the payment amount would be
7 prorated between the new meters based on usage and then split over a 20-year
8 period. The monthly surcharge will include carrying costs for the 20-year period.

9 If the customer is on Pilot Rider NAS, then Columbia would add the full cost of
10 the line extension that is subject to the Rider NAS payment terms to rate base.

11 As customers pay the monthly surcharge, the principal amounts of the payment
12 would then be applied appropriately as a customer advance to reduce rate base
13 and to the cost of service. The interest portion will be a credit to the cost of ser-
14 vice in order to compensate all other customers for the carrying costs, while the
15 reminder of the surcharge will be applied to rate base to reduce the amount. In
16 this way, over the 20 year period the payment amount would be deducted from
17 rate base and all other customers will be compensated.

18 Q. Will Customers be able to select the number of years for the Pilot Rider NAS
19 payment?

20 A. No, for administrative reasons the term will be set at 20 years for all customers.
21 Allowing each customer to pick the number of years would cause additional pro-
22 gramming changes and would increase the overall cost of offering this program.
23 However, under certain circumstances the actual term could change.

1 Q. What happens at the end of the 20-year period?

2 A. At the end of the 20 years, the surcharge will be removed from the customer's
3 bill.

4 Q. What happens if the original customer moves and someone else moves in during
5 the 20-year period?

6 A. The obligation to pay for the line extension will remain with the meter. So in the
7 case of a customer change, the new customer would be billed and would be re-
8 sponsible for the monthly surcharge.

9 Q. What happens if a customer moving into a house or building does not want to
10 pay the Pilot Rider NAS surcharge?

11 A. Paying the surcharge would be a requirement to obtain service. If the customer
12 did not want to pay the fee then Columbia would not turn on their gas. This
13 would increase the ability to collect on the payment amount.

14 Q. What happens if a customer does not pay the monthly amount?

15 A. Columbia will collect the fee from the customer using its standard collection
16 practices. Columbia requests that the Commission specifically confirm that in
17 the event that the customer does not pay, service would be subject to termination
18 and the balance of the deposit would remain in rate base. The Rider NAS charge
19 should be considered a charge, like a customer charge, that is required for the de-
20 livery of service. If a new resident would move into a premise where service had
21 been previously terminated, they would start to receive the surcharge on their
22 monthly bill.

1 Q. In the event of nonpayment would Columbia add the amount to their uncollecti-
2 ble expense?

3 A. No, any unpaid portion of the deposit would remain in rate base. Columbia
4 would not increase uncollectible expense because that would pose further costs
5 on all other customers.

6 Q. What will be the order of payment when a customer only makes a partial pay-
7 ment in a month?

8 A. Payment to the Pilot Rider NAS charge would be applied after funds are applied
9 to Columbia's other charges on the bill, but prior to any third party charges.

10 Q. What happens if, within the 20 year payback period, more customers are added
11 to the new lines than expected?

12 A. All new customers who obtain service from the new lines covered under the Pilot
13 Rider NAS would be charged the appropriate surcharge. If more customers are
14 added than planned, or if new customers are added to the extended pipelines
15 over time, then the principal amount would be collected over a shorter time
16 frame.

17 Q. What happens when a new line extension is made off of one that is covered under
18 Pilot Rider NAS?

19 A. In the case of a whole additional extension of Columbia's facilities, it would be
20 considered a new project and would go through Columbia's existing evaluation.
21 Therefore it may or may not end up with a new Pilot Rider NAS surcharge for
22 that extension. It would all depend on the economic analysis.

1 Q. If a new customer being added would want to pay their share of the deposit up
2 front, would they be allowed to do so?

3 A. No, for administrative reasons, all customers added would receive the surcharge
4 on their bill. They would receive the charge for the remainder of the original 20
5 year period or until the deposit balance is paid, whichever is shorter.

6 Q. Would the addition of more customers than expected cause Columbia to over col-
7 lect the deposit?

8 A. No, in this situation Columbia would cease to collect the monthly surcharge once
9 the full principal amount is collected. This could result in the surcharge being
10 collected in less than 20 years.

11 Q. Is it possible that Columbia could be undercollected at the end of the 20-year pe-
12 riod?

13 A. Yes. One situation that could cause Columbia to not fully recover the cost is if a
14 meter were inactive for a period of time. This would prevent Columbia from bill-
15 ing the charge for those months when the meter was inactive and, ultimately, re-
16 duce the amount of the deposit recovered by Columbia. Another scenario that
17 could lead Columbia to be undercollected is in the event a customer defaults on
18 their payments.

19 Q. Is Columbia proposing to handle all excess amounts under its main extension
20 policy under the Pilot Rider NAS?

21 A. No. Columbia has designed Pilot Rider NAS as an option that Columbia can offer
22 to customers at its discretion. Columbia anticipates some customers may still
23 prefer to pay the deposit up front rather than pay over the 20-year time period—

1 particularly if the deposit is minimal. Columbia is simply offering an additional
2 way for potential customers to contribute toward the cost of a natural gas distri-
3 bution service extension.

4 Q. Are there any limits to Pilot Rider NAS?

5 A. Yes, Columbia is setting a maximum amount per year of excess amounts that can
6 qualify for the Pilot Rider NAS option. That amount will be a maximum of \$1
7 million per calendar year.

8 Q. Why is Columbia setting a limit on the annual amount that can qualify for Pilot
9 Rider NAS?

10 A. The limit is important to the Company in order to be able to balance construction
11 of new facilities with its other obligations, to provide safe and reliable distribu-
12 tion service and to continue replacing cast iron and bare steel at its planned ac-
13 celerated pace. The level of new business construction in any year is difficult to
14 forecast because it involves many variables. If Pilot Rider NAS is successful, Co-
15 lumbia could see such a sharp increase in the number of line extensions con-
16 struction projects that it would not be able to both construct the new distribution
17 systems and also replace all of the cast iron and bare steel pipe that it is sched-
18 uled to replace. While the company is committed to assisting as many people as
19 possible to get gas service, it does not want to do so at the expense of other need-
20 ed pipeline maintenance or replacement.

21 Q. How will Columbia finance this proposal and still maintain its cast iron and bare
22 steel pipeline replacement?

1 A. The limit on the amount of deposits per year that will be permitted to qualify for
2 Pilot Rider NAS will allow Columbia to maintain its cast iron and bare steel pipe-
3 line replacement program.

4 Q. How did Columbia determine the \$1 million limit for deposits that could qualify
5 for Pilot Rider NAS?

6 A. Columbia reviewed customer deposits over the last five years and saw that it had
7 an average of nearly \$300,000 in customer deposits for line extensions in any
8 given year. Columbia believes allowing the customer to pay the deposit over a 20
9 year period will be very attractive to customers, so Columbia believes the limit
10 needs to be substantially above the historical average to accommodate all of the
11 new line extension projects. Assuming for the sake of argument that future line
12 extension projects are similar in kind and size to prior line extension projects, the
13 \$1 million limit will permit Columbia to have more than three times the number
14 of line extension projects as it has averaged over the last five years.

15 Q. Is Columbia proposing any other limits?

16 A. Yes, the surcharge will be limited to no more than \$25 per month for residential
17 customers.

18 Q. Why is Columbia putting a limit on the amount of the monthly surcharge?

19 A. Columbia is proposing a limit for two reasons. The rider itself has an overall lim-
20 it per year, and therefore by placing a cap on the monthly surcharge Columbia is
21 able to limit how much of that allotted amount is spent on any one customer.
22 This will allow Columbia to provide this service to a larger number of customers.
23 The second reason is that this limit on the surcharge will also help Columbia

1 manage the total amount spent and therefore help protect the cast iron and bare
2 steel pipeline replacement program. If Columbia calculates that the 20 year
3 payment term of an excess amount would exceed the \$25 per month cap, the cus-
4 tomer would have the option of paying the remainder as a deposit up front
5 should they want service and to keep the Pilot Rider NAS surcharge under the
6 \$25 per month cap.

7 Q. Is Columbia proposing any other changes in respect to line extensions?

8 A. Yes, as specified in the language of Pilot Rider NAS, Columbia is also requesting
9 to use additional funds that may be identified from time to time such as pipeline
10 refunds to create an internal fund to help reduce the cost of any deposits for Pilot
11 Rider NAS. This will help customers obtain natural gas service and contribute to
12 economic development in their service territory.

13 Q. Please explain what you mean by "pipeline refunds."

14 A. Pipeline refunds are any dollars that are refunded to Columbia from the inter-
15 state pipelines that Columbia contracts with for capacity. These refunds can be
16 from penalties, rate changes, or other causes and happen from time to time.

17 Q. How will this fund work?

18 A. When Columbia receives any pipeline refunds, it will reserve those funds and file
19 a request with the Pennsylvania Public Utility Commission with its proposed use
20 of the funds. This reserve will then be used to buy down no more than 25% of
21 any new deposit. The reserve will be used on a first come basis until it is used up.
22 Any unused portion of the fund will carry over year to year until it has been used
23 to buy down deposits for extension of Columbia's facilities. This reserve will only

1 be funded when Columbia receives refunds and receives permission from the
2 Pennsylvania Public Utility Commission to add those refunds to the reserve fund
3 set aside for service into new areas. The buy down will only happen in years
4 when Columbia has money in the fund.

5 Q. If Columbia requests and receives approval to add pipeline refunds into a fund to
6 buy down deposits, will the Company apply any of those refunds to any of the ex-
7 isting deposits covered under Pilot Rider NAS?

8 A. No, any funds would be reserved for new projects only. Existing customers under
9 Pilot Rider NAS would not be impacted.

10 Q. How will this impact the effectiveness of Pilot Rider NAS?

11 A. The pipeline refunds can serve to help reduce the amount that is paid over time
12 by the customer through Pilot Rider NAS. The funds would be automatically ap-
13 plied to the formula used to determine the monthly fee for the surcharge. The
14 customer would then receive the benefit of a lower monthly surcharge through
15 Pilot Rider NAS.

16 Q. Will this fund only apply to pay for facility extensions that are in the Pilot Rider
17 NAS?

18 A. Yes.

19 Q. Does this conclude your Prepared Direct Testimony?

20 A. Yes it does.

Columbia Gas of Pennsylvania, Inc.

PILOT RIDER NAS - NEW AREA SERVICE**APPLICABILITY**

Throughout the Company's service territory for any residential customer seeking natural gas distribution service or commercial and industrial customers so long as the intent of the service is primarily residential customer service.

AVAILABILITY

The Company may make Pilot Rider NAS available to any residential, commercial or industrial applicant who would be required to provide a deposit under Rule No. 8 – Extensions Rule of the Company's tariff for an extension of the Company's distribution facilities.

Pilot Rider NAS will close for new participation on June 30, 2017 unless an extension is approved by the Commission.

CHARACTER OF RATE

This Pilot Rider NAS has been established to provide customers with an alternative to paying the deposit required by Rule No. 8 - Extensions of the Company's tariff when an extension of the Company's distribution facilities is not economically feasible based on the anticipated gas requirements. Pilot Rider NAS may be used on a stand-alone basis, or in conjunction with a deposit, in order to eliminate or reduce the amount of the deposit required under Rule No. 8 - Extensions of the Company's tariff. The Pilot Rider NAS will be a flat charge per bill. The Pilot Rider NAS charge shall be calculated separately for each distribution extension project and the charge shall be based on the cost of that particular distribution extension project. The Pilot Rider NAS charge shall be calculated as described below for each customer served from that particular distribution extension project. In any year Columbia will not place an amount greater than \$1,000,000 into this rate rider.

RATE

This rate rider shall be calculated based on the applicant(s) ("Deposit Amount") and spread over a period of 20 years.

CALCULATION OF RATE

Pilot Rider NAS will use the Company's current practice to determine the economically unjustified portion of a distribution facility extension project as described in Rule No. 8 - Extensions of the Company's tariff. The Deposit Amount shall be assessed to the applicant using the following calculations:

Residential Distribution Service

When, pursuant to Rule No. 8 - Extensions of the Company's tariff, an applicant is required to provide a refundable cash deposit to the Company equal to the difference between the minimum capital investment required to serve the applicant(s)'s gas requirements and the amount of capital that the Company can justify investing in the project based on the anticipated gas requirements of the applicant(s), the Company shall have the option of allowing the applicant(s) to pay the Deposit Amount over a period of 20 years ("New Area Service Charge"). The 20 year period shall start with the first bill after the first meter is set. The New Area Service Charge shall appear as a monthly charge on the customer's bill and shall be equal to 1/240 of the difference between the

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minimum capital investment required to serve the applicant(s)'s gas requirements and the amount of capital that the Company can justify investing in the project, plus interest equal to the fixed cost of capital as approved in the most recent rate case. The New Area Service Charge shall be assessed to all customers taking residential natural gas distribution service from the distribution facility extension at any time during the 20 year period.

The maximum New Area Service Charge per month per each residential customer shall be no more than \$25 per month.

In the event that multiple residential service applicants shall be served through the extension of the Company's distribution facilities, each applicant will be assessed an equal portion of the New Area Service Charge.

The customer shall retain the right to pay the remaining balance of the New Area Service Charge at any point in time during the 20 year payback period.

Commercial and Industrial Distribution Service

When, pursuant to Rule No. 8 - Extensions of the Company's tariff, the customer is required to pay a refundable deposit in the amount that the net present value is below zero, the Company shall have the option of allowing the applicant(s) to pay the Deposit Amount over a period of 20 years ("New Area Service Charge"). The 20 year period shall start with the first bill after the first meter is set. The New Area Service Charge shall be appear as a monthly charge on the customer's bill and shall be equal to 1/240 of the net present value that is below zero plus interest equal to the fixed cost of capital as approved in the most recent rate case. The New Area Service Charge shall be assessed to all customers taking commercial or industrial distribution service from the distribution facility extension at any time during the 20 year period.

In the event that multiple commercial and industrial applicants shall be served through the extension of the Company's distribution facilities, each applicant will be assessed a prorated portion of the New Area Service Charge as determined by the projected usage of each customer.

The customer shall retain the right to pay the remaining balance of the New Area Service Charge at any point in time during the 20 year payback period.

In the event multiple rate classes of applicants shall be served through the extension of the Company's distribution facilities, each class will be assessed its prorated portion of the New Area Service Charge first, then each applicant within each class will be assessed its share as described in this Rider.

PERIODIC ADJUSTMENTS

The Company shall retain the right to adjust customers' deposit in the event that additional meters are added to or removed from the distribution facility extension. These adjustments shall include altering the New Area Service monthly charge assessed to customers and/or decreasing or increasing the 20 year payback period.

ADDITIONAL CREDITS

The Company shall retain the right to apply credits, at its sole discretion, to the New Area Service Charge thereby reducing the total amount owed by the Customer during the 20 year period.

TERMS OF PAYMENT

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If the customer fails to pay the full amount of any bill a delayed payment penalty charge of one and one-quarter percent (1 1/4%) per month will accrue on the portion of the bill that is unpaid on the due date. The delayed payment penalty charge will not count as money paid towards the Deposit Amount due for any reconciliation period.

RECONCILIATION

At the conclusion of the 20-year period, the Company shall retain the right to extend the Rider NSA for a period of time necessary to collect any outstanding amount. The customer(s) will continue to be assessed the same monthly rate.