Columbia Gas of Kentucky
A NiSource Company

September 3, 2009

Mr. Jeff Derouen
Executive Director
Public Service Commission
Commonwealth of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602

RE: Case No. 2009-00141

Dear Mr. Derouen,

Enclosed for filing are the original and ten (10) copies of Columbia Gas of Kentucky, Inc.'s Prepared Rebuttal Testimony in the above case. Should you have any questions about this filing, please contact me at 614-460-4648. Thank you!

Sincerely,

Stephen B. Seiple

Stephen B. Seiple
Assistant General Counsel

Enclosures

cc: All Parties of Record
Hon. Richard S. Taylor

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Prepared Rebuttal Testimony of Columbia Gas of Kentucky, Inc., was served upon all parties of record by regular U. S. mail this 3rd day of September, 2009.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.) Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF
DAVID E. MUELLER
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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF DAVID E. MUELLER

Q: Please state your name and business address.

A: My name is David E. Mueller and my business address is Columbia Gas of Kentucky, 2001 Mercer Rd., Lexington, Kentucky.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Glenn A. Watkins filed Direct Testimony on behalf of Kentucky Office of Attorney General related to Columbia's proposed Accelerated Mains Replacement Program ("AMRP"). This testimony will rebut Mr. Watkins' understanding that under the AMRP Columbia will prematurely replace its priority pipe, as well as his assertion that replacement of aging infrastructure does not create an extraordinary financial burden for Columbia.

Q. As stated in the first question on page 38 of Mr. Watkins' testimony where he describes his understanding of the description of Columbia's proposed AMRP, is his characterization accurate?

A. To the extent that Columbia is requesting a rider to recover investment of certain types of plant facilities it is accurate. However, the abbreviated description of the specific facilities covered by the AMRP is not. As stated on page eight (8) of my direct testimony, "The types of main identified for replacement in Columbia's AMRP are unprotected bare steel, cathodically protected bare steel, cathodically un-protected coated steel, ineffectively coated steel and cast iron. Columbia considers these types of gas distribution main, 'Priority Pipe' or 'Priority Main'. As part of its AMRP, Columbia also intends to replace all metallic service lines, and service lines which do not meet current material and construction standards. Columbia plans to replace these mains, service lines, and associated appurtenances…"

Q. On page 38 of Mr. Watkins' testimony he characterizes as premature Columbia's need for a program to replace metallic pipe over the next thirty years. Do you agree with Mr. Watkins?

A. No, I do not. The purpose of the AMRP is principally to ensure continued public safety and system reliability by replacing facilities subject to the effects of accelerated corrosion. As explained in my direct testimony and corroborated by the direct testimony of Columbia witness Vitale, that part of Columbia's system identified as priority pipe is nearing the end of its useful life. More than 70% of the corrosion leaks found on Columbia's system occur on 19% of its distribution mains and 10% of its services respectively. In spite of efforts on the part of Columbia to deal with accelerated leakage on its facilities, annual leakage rates are beginning to trend upward. As explained in attachment SV-1 to the Direct Prepared Testimony of Columbia witness Vitale, Comparative Analysis of the Non-Cathodically Protected Bare Steel Distribution Piping of Columbia Gas of Kentucky, Inc. leakage rates, associated with corrosion left unaddressed, will accelerate very rapidly until the metallic pipe is totally consumed. Therefore, failure to replace priority pipe in a planned and coordinated manner will result in failure rates that exceed Columbia's capital and physical resources needed to safely respond to accelerating leakage rates.

Q. Will a 30-year program provide an adequate timeframe for Columbia to address accelerating leakage and failure rates?

A. Deciding on the duration of a replacement program requires balancing risk, resource availability, and financial impact to our customers. Choosing a duration that is too long will eventually result in accelerated leakage rates as buried piping ages. Ultimately the leakage rate will increase to point that it will overwhelm our resources, increase risk to public safety, and impose additional financial burden on our customers. Choosing a duration that is too short while has the affect of reducing some risk, will effectively amortize the returns over a shorter period of time, imposing a greater financial impact on customers at any given time.

While deciding on a suitable replacement duration for Columbia's operating system we considered the following four factors;

- Age distribution of the priority pipe;
- Current leakage rate trends;
- Resources available to operate and maintain the gas systems; and,
- Tools available to help manage risk.

Looking at the data extracted from DOT annual reports and the data assembled by witness Vitale, with Black and Veatch the oldest pipe pre-dates 1940 aging it at approximately 70 years. Furthermore, about half of the priority pipe was installed pre-1940 to about 1950 and the majority of the remaining pipe footage from approximately 1950 to 1959 aging the last of the priority pipe approximately 40 years.

When considering risk associated with operating a natural gas system comprised of a large amount of priority pipe, all things being equal, age is highly correlated to leakage rates as established by the testimony of witness Vitale. As a matter of science and experience, all things being equal, once unprotected pipe reaches a certain age, the leakage rate often accelerates very rapidly. However, the information provided by witness Vitale, also demonstrates that leakage rate per year over the past several years for Columbia, aside from some variability, is fairly steady. Comparing Columbia's leakage repair rates, against the resources currently available, led to the conclusion that Columbia can safely manage the risk associated with the age and condition of its system.

Taking the age distribution of the priority pipe together with current resource availability, the current leakage rate, and assuming that all the factors affecting pipe integrity and risk remain the same, at the end of a 30-year replacement period, the oldest pipe will be no older than Columbia's oldest pipe today, thereby, assuming a similar level of risk and maintaining adequate resources to operate and maintain Columbia's distribution system.

Columbia's analysis is a reasonable approach and strikes a balance between operating risk and financial considerations. While 30 years is a reasonable estimate for project duration in the beginning, we also recognize that a strictly linear approach to replacement will not likely realize the desired results. For this reason Columbia routinely considers the input from newly acquired risk management tools, and cross-functional teams comprised of engineering, operations, construction, regulatory affairs, capital allocation, and communications to validate the assumptions made when selecting projects and establishing annual budgets. By using this method Columbia will likely accelerate or decelerate its replacement program in any given year based on unforeseen safety, operating or maintenance considerations, resource availability, and financial impacts to its customers. Furthermore, based on the comparative analysis of Columbia's infrastructure performed by Black and Veatch, they formed an opinion that this rate of replacement is a reasonable expectation and that it should provide a significant improvement in the safety and reliability of Columbia's distribution system.

Q. Mr. Watkins states on pages 39 and 40 that because Columbia did not previously have a formal repair/replacement policy, was unable to provide replacement footages and costs between 1995 and 2003, and did not implement a coordinated replacement program years ago that Columbia has not considered pipe replacement now either an emergency or extraordinary. Do you agree with this conclusion?

A. No, I do not. Despite not having a formal replacement program, Columbia has always focused its operating efforts on safety. Columbia's inability to provide the requested replacement data was only due to the inability to gather the data in the limited time frame permitted for responses to discovery requests. This does not suggest that past system and financial performance has been unimportant to Columbia in making repair and replacement decisions. Columbia has constantly maintained surveillance of its systems, and as Columbia witness Vitale also discusses in his Prepared Rebuttal Testimony, Columbia has historically sought to extend the economic value of its distribution system, thereby minimizing financial impact to its customers by managing its resources to adequately extend the serviceability of its assets and still maintain safe operations. As described in my direct testimony, Columbia addresses leakage control in its written operating and maintenance plan to ensure public safety and reliability. Furthermore, Columbia has always maintained a policy to prioritize and replace unserviceable pipe that was financially unviable to rehabilitate. Historically, Columbia has annually replaced approximately 10 miles of priority main and the associated services and appurtenances. While Columbia has successfully balanced its physical and financial needs to repair leaks and replace pipe over the past 38 years, because of the accelerating leakage rate, continuing at this current replacement rate is now inadequate and will exceed the available resources necessary to safely respond to accelerating leakage rates in the future. Columbia believes that now is the prudent time to address this issue.

Q. Do you agree with Mr. Watkins' assertion on page 38 of his testimony that without the AMRP Rider no extraordinary financial burden on Columbia exists?

A. No, I do not. Under the AMRP Columbia will replace more than 20% of its mains, services and associated facilities costing approximately $210 million. Amortized over approximately thirty years, this will significantly increase Columbia's annual capital requirements. While public safety and potential risk are always a priority, the timing and extent of replacement cost recovery can impact the scope of replacement projects in any given year. Fair and timely investment recovery via the "AMRP Rider" explained in Columbia witness Cooper's testimony, provides a critical and predictable base of capital to finance the AMRP over approximately the next thirty years. As explained previously in this rebuttal testimony, failure or delay in establishing a predictable source of capital can quickly outpace Columbia's resources that could negatively impact Columbia's ability to safely respond to the risk associated with accelerating system deterioration.

Q. Are there any other financial considerations associated with the AMRP?

A. Yes. As explained at length in my direct testimony and in Columbia witness Vitale's rebuttal testimony, a well planned, systematic approach to replacement as defined by the AMRP, that is adequately funded is more cost efficient and results in less financial burden to Columbia's customers. New prioritizing tools, such as Optimain, will aid in replacement decisions that focus on the highest priority pipe, decreasing risk to public safety, and aid Columbia's efforts to structure large replacement projects. A large project approach is a much more cost effective than a smaller discrete project approach, because it takes advantage of economies of scale to leverage material, contractor and labor costs associated with large well defined replacement projects.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF
DR. STEVEN VITALE, PH.D., P.E,
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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF DR. STEVEN VITALE

Q: Please state your name and business address.

A: My name is Steven Vitale and my business address is 118 Fern Drive, PMWF, Milford, Pa. 18337

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Glenn A. Watkins filed Direct Testimony on behalf of Kentucky Office of Attorney General related to Columbia's proposed Accelerated Mains Replacement Program ("AMRP"). This testimony will rebut Mr. Watkins' statement that Columbia should have begun its Accelerated Mains Replacement Program in 1971.

Q: Do you agree with Mr. Watkins' opinion on page 39 of his testimony that, "DOT's position regarding the installation of bare steel piping should have been significant enough to initiate a program of accelerated pipe replacement in the interest of safety and quality of service to the Company's customers some 38 years ago"?

A. No I do not.

Q: Can you please explain why you disagree with his opinion?

A: From Mr. Watkins' testimony it appears that he based his opinion solely on a change in the DOT code that took place in 1971, and his opinion suggests that he may not have a full understanding as to what lead to the change or how natural gas distribution systems are designed, constructed, operated and maintained.

In 1971 the DOT stopped allowing the use of cast iron and bare steel for new construction of gas mains and services. This was the result of the industry and the DOT realizing that such materials were inferior to the newer technologies then available (such as cathodically protected coated steel and plastic). It was also understood that the performance and or life expectancy of cast iron and non-cathodically protected bare steel was less than that of the newer technology pipe materials.

However, in 1971 the DOT did not mandate the removal of existing bare steel and cast iron pipe. Instead it relied on the engineering, operating and maintenance experience and best judgment of utility gas distribution system operators. These gas utility operators understand and monitor the character of their gas systems and manage the risks associated with these piping materials, with the knowledge that such risks are utility specific. They are utility specific because each utility has its own legacy pipes, soil conditions, past installation procedures, gas distribution system design, as well as, building and street characteristics unique to its service territory.

Rather than beginning an AMRP program in 1971 as suggested by Mr. Watkins, Columbia followed what I believe was a more prudent approach of monitoring and continuously evaluating the condition of its bare steel piping and replacing poor performing sections of pipe as necessary based on its analysis of corrosion-related leak and other data collected by company employees.

Q: Do you think that Columbia's AMRP plan is a better course of action compared to Mr. Watkins' suggestion?

A: Yes I do. I believe that Columbia's process of managing its pipelines is in the best interest of its customers. Columbia has used and continues to use the best judgment of its experienced staff to manage the risk associated with these piping materials. This risk management is done by balancing the cost effectiveness of repair vs. replacement decisions against the safety and system reliability associated with such decisions. While it was undoubtedly understood by Columbia in 1971 that there was significant useful life remaining in much of the bare steel still in use in their system, it was also understood that these materials would need to be replaced at some point in the future. There is no fixed formula for these decisions. Instead these decisions are structured after years of field experience and data, supported by science and lessons learned from the industry.

Today Columbia has the benefit of improved pipeline risk management decision support tools such as Optimain, as well as newer installation technologies that have reduced the cost of replacing these types of mains and services.

The Optimain tool helps Columbia optimize the AMRP by helping it determine which mains should be replaced first for the best management of these higher risk mains. In addition, Columbia's mains and services replacement work queue will allow for the combining of many work tasks to optimize the performance of the work while minimizing the inconvenience to the customer. These processes will also be interfaced with planned city and state construction and with the system reinforcement and reliability programs needed for a safe, reliable, and cost effective gas distribution system. Such a planned program can also potentially improve contractor main and service replacement contract costs due to economies of scale. These benefits will be dovetailed with new technologies such as improved trenchless excavation and field proven plastic materials.

Such efficiencies would not have been possible in 1971. Further, if the company had followed Mr. Watkins' logic, in earlier decades much of the piping would have been replaced prematurely, in other words, before the end of its useful life, which would have been to the economic detriment of Columbia's consumers.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF JUDY M. COOPER ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF JUDY M. COOPER

Q: Please state your name and business address.

A: My name is Judy M. Cooper and my business address is 2001 Mercer Road, Lexington, KY.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Jack E. Burch filed Direct Testimony on behalf of the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc., ("CAC"), Nancy Brockway filed Direct Testimony on behalf of AARP and Robert J. Henkes and Glenn A. Watkins filed Direct Testimony on behalf of the Attorney General ("AG"). This testimony will rebut the following issues addressed by those witnesses: (1) Columbia's proposed reconnection fees; (2) Columbia's proposed late payment penalty; and, (3) the AG's Miscellaneous Service revenue adjustment.

__Reconnection Fees__

Q: On page 13, lines 5-6 of his testimony, Mr. Burch states that, "...the Company's desire to recover its actual reconnection costs is legitimate, we believe this new fee to be, nevertheless, to high for its poorest customers." Is the reconnection fee a new fee?

A: No, the reconnection fee is not a new fee. The amount of the fee is proposed to increase from the existing amount of $25 to $60 based upon the cost of providing the service. The reconnection fee is a special charge, the theory of which is set forth in 807 KAR 5:006 Section

8 and pursuant to the regulation, is to be applied uniformly throughout the area served by a utility.

Q: **On page 13, lines 9 – 10 of Mr. Burch suggests that Columbia consider other options, including delaying disconnection of service for low-income customers. On page 17, lines 14 – 21 of her testimony, Ms. Brockway suggests offering budget counseling, assistance referrals and other actions, integrated by the utility with collections as part of the utility's revenue assurance team. Does Columbia currently offer any options to delay disconnection of service for low-income customers and provide assistance?**

A: Yes. Any customer, regardless of income, may delay disconnection of service for non-payment by entering into a payment plan with Columbia. Disconnection of service may also be delayed if a medical certificate is presented stating that termination of service will aggravate a debilitating illness or infirmity on the affected premises. Assistance is available to any customer that contacts Columbia about payment troubles, regardless of income, in the form of individual payment plans for arrearages, budget billings and referrals to other agencies for assistance, including CAC. As stated on page 3 of Mr. Burch's testimony, the CAC provides a comprehensive approach to the multiple obstacles and barriers that most low-income households face. Columbia refers customers to CAC so that the customers can take advantage of the expertise of the CAC. This allows customers to maintain greater financial stability and self-sufficiency.

Q: On page 13, lines 14-15, Mr. Burch explains how some assistance programs require a disconnect notice in order for a customer to be eligible for benefits. Does issuance of a disconnect notice always mean that a reconnection fee is assessed?

A: No. A disconnect notice, or termination notice, is issued at least ten (10) days prior to the date when service may be terminated and provides the contact information of assistance agencies. This allows the customer time to avoid actual termination of service and therefore avoid the reconnection fee altogether.

Q: On page 18, lines 32-33, of Ms. Brockway's testimony she suggests that the costs of reconnection should be rolled into rates instead of being recovered via direct allocation. Similarly, on pages 35 and 36 of his testimony, Mr. Watkins opposes the magnitude of the proposed reconnection fee increase from $25 to $60 and recommends the increase be cut in half for this case. What is your opinion of these recommendations?

A: As suggested by the testimony of Ms. Brockway, the alternative to increasing the special charge for reconnection of service is to roll the costs into base rates. This would be the result of Mr. Watkins' recommendation. As shown on Attachment JMC-1 to my Direct Testimony, the total cost of the reconnect service is slightly more than $60, so a small amount of the costs are already rolled into base rates under Columbia's proposal. I do not agree with Mr. Watkins recommendation to cut the increase in half for this case and thus transfer more of the cost recovery to other customers via the base rates. The cost should be recovered from the cost causer.

Q: On page 36, Mr. Watkins opposes the magnitude of the reconnection fee associated with the request of a customer that requested disconnection of service within eight months and suggests the increase be rejected in its entirety and the reconnection fee be maintained at current levels? What is your opinion of this recommendation?

A: As stated on page 38, lines 9-12 of Mr. Watkins' testimony, the purpose of the fee is to deter seasonal customers from abandoning service during the off-season (thereby avoiding the monthly customer charge) and then reestablishing service at the beginning of the next seasonal use period. The purpose of the fee deteriorates if the fee is not equivalent to the previously approved formula, that is, eight times the applicable monthly customer charge. Therefore, Columbia does not agree with Mr. Watkins' recommendation.

<u>Residential Late Fee</u>

Q: On pages 12 – 14 of his direct testimony, Mr. Burch challenges the proposed late payment penalty and increased reconnection fee as negatively impacting low-income customers and the amount of energy assistance available to help them. On page 19 of her testimony, Ms. Brockway discusses her opposition to the residential late payment fee. On page 14, lines 4-7, Mr. Burch specifically discusses the function of the proposed late payment penalty. Do you agree with the statements of these intervenor witnesses?

A: I agree with Mr. Burch's statement that the function of a late payment penalty is to discourage late payments and with Mr. Brockway's acknowledgement that late fees get the attention of customers who have the money and are simply ignoring the bill. I also agree with Mr. Burch that many low-income customers would not incur the penalty. I do not agree that the effect of the penalty is lost on low-income customers. As described on page 12, lines 19-20 of Mr. Burch's testimony, in the choices that low-incomes households face between paying for food, prescriptions and utilities, the lack of a late payment penalty on a Columbia bill may be an incentive to choose payment to another utility first, if that utility does assess a late payment charge.

Q: Do any of the utilities overlapping Columbia's service territory assess a late payment charge?

A: Yes. In every county that Columbia serves, the electric energy utility assesses a late payment charge of 5%.

<u>**Miscellaneous Service Revenue Adjustment**</u>

Q: Do you agree with the Miscellaneous Service revenue adjustment in the amount of $72,845 included in Schedule RJH-6 of Mr. Henkes' testimony?

A: I do not agree with the amount of the Miscellaneous Service revenue adjustment because I do not agree with the recommendation of Mr. Watkins, upon which the revenue adjustment is based. Mr. Watkins recommended that the proposed reconnection fee increase be cut in half in this case. The cost of reconnection should be assigned to the users of the service as provided in 807 KAR 5:006. As Mr. Watkins noted, the increase is not gradual, but is a one-time increase. The increase will properly assign the cost and results in Columbia's proposed Miscellaneous Services revenue adjustment of $145,845.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF WILLIAM STEVEN SEELYE ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

September 3, 2009

PREPARED REBUTTAL TESTIMONY OF WILLIAM STEVEN SEELYE

Q: Please state your name and business address.

A: My name is William Steven Seelye and my business address is 6001 Claymont Village Drive, Suite 8, Crestwood, KY, 40014.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony on behalf of Columbia Gas Company of Kentucky's ("Columbia" or "Company"), the following witnesses submitted direct testimony concerning Columbia's proposed DSM programs and cost recovery mechanism: (i) Glenn A. Watkins testifying on behalf of the Attorney General, (ii) Nancy Brockway testifying on behalf of AARP, and (iii) Jack E. Burch testifying on behalf of the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"). Mr. Watkins has two minor disagreements with Columbia's DSM proposal. First, he recommends that the Company not offer rebates for natural gas furnaces and gas logs. Second, he recommends that DSM costs and incentives be recovered though a volumetric charge rather than a fixed monthly charge. Ms. Brockway argues that Columbia has not gone far enough with its DSM proposal. Although she does not recommend that the DSM proposal be rejected, she criticizes the Company for not implementing more aggressive DSM programs, particularly programs targeted to low-income customers. Mr. Burch, on the other hand, offers testimony in support of Columbia's low-income high efficiency furnace replacement program, indicating that it represents an "excellent start". (Birch Direct Testimony, page 17, line 3.)

My testimony will rebut Mr. Watkins' recommendation that the Company not offer rebates for natural gas furnaces and gas logs, Mr. Watkins' recommendation that the DSM costs and incentives be recovered through a volumetric charge rather than a fixed monthly charge, and Ms. Brockway's suggestion that Columbia Gas did not go far enough with its DSM programs, particularly low-income programs.

Q: Attorney General Witness Watkins recommends that Columbia Gas not offer rebates for gas fireplaces and gas logs in connection with its DSM Program. Do you agree with this recommendation?

A. No. By Mr. Watkins' own admission, gas fireplaces and gas logs are highly efficient. (Watkins Direct Testimony, page 44, line 19-22.) With efficiencies that often exceed 99 percent, they are some of the most efficient gas heating appliances available. These extremely high-efficient appliances should not be excluded from the DSM program because of Mr. Watkins' preconceived notion that they may also serve an "aesthetic" purpose.

Because gas fireplaces and gas logs can be installed in specific high-use areas of a home, such as a bedroom or family room, the heating requirements of low-use areas can be dialed back in order to achieve even greater overall effectiveness. For example, a gas fireplace or gas logs can be installed in a bed-room and adjoining family room which will allow the homeowner or occupant to lower the thermostat setting of the central heating system serving the whole house. Gas furnaces and gas logs can therefore be used to focus energy consumption within a particular region of the house. A similar strategy is often used with small electric space heaters; however, gas fireplaces and gas logs, which can be 99 percent efficient, are ultimately more efficient than small electric space heaters.

Q: In addition to the obvious efficiency benefits of gas furnaces and gas logs, are there other reasons for including rebates on these appliances in the DSM program?

A. Yes. One of the objectives of Columbia's initial DSM effort is to develop a set of programs with broad customer appeal in order to build enthusiasm and support for its DSM efforts across its entire customer base. Columbia did not want to develop a set of programs targeted to just one economic group, such as low-income customers. With audits, high-efficiency furnace rebates, high-efficiency water heaters, high efficiency gas fireplaces, high efficiency gas logs, and low-income high efficiency furnace rebates, Columbia has developed programs that will promote energy efficiency across and support among a wide range of customers – low-income, medium income, and perhaps even high income customers. Because all residential customers will be contributing toward the cost of the programs, all customers should feel that they have an opportunity to participate in the program. While middle and upper income customers may not be able to participate in the low-income furnace replacement program, they may be able to participate in the other programs, including rebates for the installation of high-efficiency gas fireplaces and gas logs. Just as it is important to include a DSM program that can be utilized by low-income customers, in developing a balanced DSM initiative it is important to offer a fairly wide set of measures that are likely to appeal to other customer segments.

Q: Has the Commission approved DSM rebates for gas fireplaces and gas logs for any other utility?

A. Yes. The Commission approved rebates for gas fireplaces and gas logs in Case No. 2008-00062 for Delta Natural Gas Company.

Q: Attorney General Witness Watkins recommends that DSM costs and incentives be recovered through a volumetric charge rather than a monthly fixed charge. Do you agree with this recommendation?

A. No. Recovering DSM costs and incentives through a monthly fixed charge is consistent with the Company's proposal to adopt a straight fixed variable rate design. Under a straight fixed-variable rate design, all fixed costs would be recovered through a monthly fixed charge. Because Columbia is proposing to phase in a straight fixed-variable rate design over two years, Columbia and I concluded that it would not make sense to include both a fixed monthly charge component *and* a volumetric component in the DSM cost recovery mechanism for the first twelve month period and then move to a fixed monthly charge component thereafter.

Q: Mr. Watkins claims that recovering DSM costs through a fixed monthly charge is "inequitable and discriminatory on its face". Is he correct?

A. No. There is no basis for this accusation. In fact, recovering DSM costs through a volumetric charge would be more inequitable and discriminatory than recovering these costs through a fixed monthly charge. Because these DSM costs are fixed costs, there is no basis for recovering these costs as a volumetric charge. His suggestion violates the well accepted ratemaking principle that fixed costs should be recovered through fixed charges, such as a monthly fixed charge, while variable costs should be recovered through variable charges. In making his recommendation, Mr. Watkins has made no effort to show that the DSM-related costs are variable costs. Violation of this well accepted ratemaking principle results in intra-class subsidies, which are in effect inequitable and discriminatory. Virtually all of an LDC's non-gas costs are classified as fixed costs in a cost of service study. There is no basis for arguing that the recovery of DSM costs though a fixed charge is "inequitable and discriminatory on its face." In fact, it is Mr. Watkins suggestion of recovering these DSM related costs through a volumetric charge that would result in inequitable and discriminatory treatment of customers within the residential class.

Q: As a practical matter, would recovering DSM costs through a fixed charge as opposed to a volumetric charge have much effect on customer bills?

A. No. Mr. Watkins claims that a fixed monthly charge would be unfair to customers that use natural gas exclusively for cooking. However, Mr. Watkins would be hard pressed to find a residential customer on Columbia's system that uses natural gas only for cooking. Considering that the total DSM cost to be recovered through the mechanism is less than $1 million, the difference between the two approaches on any actual residential customer served by Columbia (as opposed to a hypothetical customer that only uses natural gas for cooking) would be insignificant.

Q: Do you agree with Ms. Brockway that Columbia Gas should be more aggressive in the implementation of low-income DSM programs?

A. Columbia's proposed DSM programs represent an excellent initial effort in this area, as recognized by Mr. Burch. Based on my knowledge of the Company, Columbia operates a lean organization and is not currently staffed to implement a larger DSM program such as the Low Income Usage Reduction Program offered by its affiliate, Columbia Gas of Pennsylvania, as suggested by Ms. Brockway. Furthermore, Columbia Gas of Pennsylvania is a much larger utility than Columbia Gas of Kentucky. Almost always, beginning small and then expanding existing programs or developing new programs over time that prove to be effective is a good way to gain experience with DSM and avoid big mistakes. I have worked with a number of utilities that now have substantial DSM programs, and all of them started with a somewhat modest set of programs. In Kentucky, this is the approach that has been used by Louisville Gas and Electric Company and Kentucky Utilities, and it is also the approach now being pursued by Delta Natural Gas Company. From my own experience, starting small and then growing the programs that prove to be effective is a better approach than committing to more than the utility can actually deliver and giving DSM a bad name among customers.

While the AARP's desire for a greater commitment from Columbia for low-income DSM programs is understandable, Ms. Brockway should also realize that it is extremely difficult to develop low-income DSM measures that are affordable to this targeted group of customers, but are also cost effective in terms of the standard cost-effectiveness tests used to evaluate DSM programs, such as the Total Resource Cost ("TRC") test. Even though the low-income furnace replacement program proposed by Columbia has a low TRC ratio (less than 1.0), the Company concluded that it is important to offer at least one program targeted to low-income customers. Without the low-income furnace replacement program, it is unlikely that low-income customers would be able to take advantage the other DSM programs to be offered by Company.

Because all customers are supporting the DSM effort financially, it would be inappropriate, however, to focus on just one customer segment, as Ms. Brockway seems to recommend. As noted above, Columbia has structured a portfolio of DSM programs that are targeted at the entire spectrum of residential customers in order to build wide support for these programs. If these programs are perceived as just being targeted at the low-income segment, a broad based support for DSM may not develop.

However, it is important for the AARP to understand that Columbia does not intend to develop future programs in a vacuum. If the AARP has specific low-income programs that it believes should be considered, then the AARP should propose the formation of a collaborative group to explore the feasibility of those programs.

Q: Do you have any concluding comments about the need for Columbia to adopt a straight fixed variable rate design?

A. Yes. The adoption of a straight variable rate design represents a significant step toward removing a major impediment for Columbia to enthusiastically embrace energy efficiency on the part of its customers. As a result, I find it somewhat disheartening that although AARP witness Brockway and AG witness Watkins seem to approve of utility-sponsored DSM programs, both witnesses object to the implementation of a straight fixed variable rate design which would remove the disincentives associated with improved energy efficiency by customers. If there is a desire for utilities to enthusiastically embrace demand-side management and energy efficiency, it is imperative that they be allowed to adopt a straight fixed variable rate design or some other form of decoupling. By decoupling revenues from sales, a straight fixed variable rate design protects the utility against the deterioration in its earnings due to the impact of *either* DSM initiatives sponsored by the utility *or* energy conservation efforts initiated by customers on their own behalf. Allowing utilities to adopt straight fixed variable rate design or other form of decoupling will remove a major obstacle preventing utilities from fully supporting energy efficiency. Based on my experience working with utilities around the country, I have concluded that utilities will enthusiastically embrace energy efficiency if the inherent disincentives associated with the lost revenues and margins resulting from improved energy efficiency are removed.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF JAMES F. RACHER ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

September 3, 2009

PREPARED REBUTTAL TESTIMONY OF JAME F. RACHER

Q: Please state your name and business address.

A: My name is James F. Racher and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Robert J. Henkes filed Direct Testimony on behalf of the Attorney General related to the revenue requirement for Columbia Gas of Kentucky ("Columbia"). This testimony will rebut the following issues: (1) the adjustment to the accumulated depreciation reserve balance; (2) the pricing of stored gas inventory for rate base purposes; (3) the exclusion of wage increases for union employees; (4) the exclusion of incentive compensation; (5) the proposed level of uncollectible expense; (6) the proposed amortization period for rate case expense; (7) the exclusion of business promotion expenses; (8) the exclusion of SERP expenses; and, (9) certain corrections to Mr. Henkes' proposed revenue requirement.

Q: Do you agree with Mr. Henkes' recommendation on pages 8 and 9 of his testimony that the pro forma test period accumulated depreciation reserve balance be adjusted for changes to pro forma depreciation expenses?

A: No, I do not.

Q: Can you please explain why you disagree with his recommendation given that the Commission has approved this treatment for many years?

A: Columbia is aware that, in other cases, the Commission has included proposed adjustments to depreciation expense as an adjustment to the accumulated depreciation balance utilized in the calculation of rate base. Such an adjustment would have the effect of reducing rate base by an amount not yet recovered from customers, which would be inappropriate. The linkage between allowance for depreciation expense (return of) and return on rate base (return on) capital expenditures made by a utility is that until the utility's investment in an asset is recovered from the customers through incorporating an approved level of depreciation in rates, then the utility should recover a fair and reasonable return on the existing or remaining unrecovered investment. This linkage would be broken by reducing rate base for a depreciation level not yet incorporated in, billed, and recovered through rates.

Furthermore, the adjustment to the accumulated reserve is just one side of the rate base equation. Using the end of test year level of rate base provides a reasonable estimate of the rate base level expected to be in place and funded by investors during the first twelve months rates are in effect. Including an adjustment to the reserve, without any recognition of any future plant additions, particularly non-revenue plant additions, distorts the level of rate base expected to be in effect during the first twelve months of the new rates. Absent the plant additions from Columbia's Accelerated Main Replacement Program which will be addressed through Columbia's proposed Accelerated Main Replacement Rider, the rate base Columbia proposed in this case represents the minimum level that will be in effect during the rate year.

Q: Mr. Henkes' opinion on pages 10 through 14 of his testimony is that the per book 13-month average test year balance of stored gas inventory be used in determining rate base. Do you agree with his opinion?

A: I agree that the 13-month physical gas volume balance should be used, however I do not agree with the LIFO valuation of those volumes. The LIFO valuation methodology does not accurately reflect the cost of gas in storage as a component of rate base. Columbia must first purchase gas that is injected into storage for future use through withdrawals. The value of gas in storage at its weighted average purchase cost can be measured at the end of the normal storage injection period (October). This level reflects gas purchased at various prices over many years.

On page 12 of his testimony, Mr. Henkes contends that the October average inventory valuation rate should not be used to value stored gas for rate base because it exceeds the 13-month average inventory LIFO valuation rate in subsequent periods. However, distorted and negative storage value months are included in the months that make up the 13-month averages used in his comparison. Including negative values in amounts making up this average lowers the average. As I have mentioned previously, negative storage value in months in which physical gas remains in storage is not logical from a working capital perspective as it suggests a source of funds for Columbia. Indeed, Mr. Henkes acknowledged in response to Columbia's request number 66 to the AG that negative dollar balances in storage are not a source of funds and he agreed physical volume remains in the storage facility during those months in which the value of storage was negative.

The comparison on page 13 of Mr. Henkes' testimony shows the valuation of storage using the October average inventory rate times the 13-month volume is higher than the 13-month average based on the per book LIFO method. Again, this is a result of the variations in monthly valuation of storage in the months making up the 13-month average balances. These variations include months in which storage had a negative value. Referring to the response to data request AG 1-011, the variations in the test year value of gas in storage ranged from \$(24,046,822) for 1,154,953 Dth in March to \$81,472,966 for 11,443,831 Dth in October. The resulting average rates per Dth were \$(20.82)/Dth for March and \$7.12/Dth for October.

Valuing stored gas volume at the weighted average rate at the end of the injection cycle as proposed provides appropriate consideration for the value of storage for ratemaking purposes versus the LIFO method.

Q: Do you agree with Mr. Henkes' recommendation on pages 18 and 19 of his testimony that the union wage increase be disallowed?

A: No, I do not.

Q: Please explain why you disagree with his recommendation.

A: The test year union wage costs are not representative of the costs Columbia knows that it will incur during the rate year because Columbia has a contract with its union employees for a wage increase effective December 1, 2009. Mr. Henkes acknowledges the percentage of the wage increase is known and measureable on page 19 of his testimony and indicates that the employee level has dropped by 3 from the test year level. As shown on Columbia's response to PSC data request 2-1, the number of union employees at the end of the test year was 92. In Columbia's response to AG data request Set 2, number 16, the June, 2009, number of union employees was 91, a difference of 1 union employee due to a vacancy. Columbia's response to AG data request 2-16 further noted that Columbia was in the process of filling the union position vacancy. Therefore, the complement of union employees has not changed from the test year level and the union wage increase should be allowed as a known and measurable cost Columbia will incur during the rate year.

Q: Has the Commission approved this type of post test year adjustment in the past?

A: Yes. I understand a similar adjustment was approved in Louisville Gas and Electric Company's 2000 rate case, Case No. 2000-00080. The Commission allowed the union wage increase effective 10 months beyond the test year indicating that a contract union wage increase constitutes a known and measureable adjustment.

Q: What is the level of the union wage increase per the contract?

A: As shown on Columbia's response to PSC data request 2-22, the union wage increase is 3.5% and also includes a $0.15/hr. structure adjustment. Columbia's response to AG data request Set 1, number 60 also shows information related to the labor increase.

Q: On pages 20 to 26 of his testimony, Mr. Henkes' puts forth his opinion regarding treatment of Columbia's and NiSource Corporate Services Company's ("NCSC") incentive compensation and profit sharing expenses. Do you agree with his treatment?

A: No, I do not.

Q: Please explain why you disagree?

A: Incentive compensation and profit sharing are an important component of the total compensation as required for Columbia and NCSC to be effective in recruiting and retaining employees. Columbia's incentive compensation plan is designed to motivate individual employee performance in furtherance of key operating goals that are identified as necessary to maintain a high level of customer service, efficient operations and financial integrity. To achieve the identified operating goals, NiSource ties a portion of each exempt employee's total annual compensation to the achievement of the incentive program goals. The program goals include the employee's individual performance on a number of very specific customer service, efficiency, and safety goals, as well as certain financial goals at the corporate and business-unit levels. These goals are documented in each employee's performance management worksheet, an important element in evaluating an employee's performance during the year.

Q: What goals are included in an employee's performance management worksheet?

A: The actual performance management worksheet goals for Dave Mueller, the CKY Operations Center Manager, are below:

- Manage O & M Expenses to Budget Level. Conduct quarterly detailed O&M reviews with each direct report.
- Partnering with supply chain and others to assure the best price for labor, materials, supplies, etc.
- Improved Safety Metrics: For Gas Distribution Operations the number of Days Away from Work injuries will be less than or equal to 25.
- Performance Management: All eligible employees have a Performance Management Worksheet.
- Operate Consistent with Compliance Requirements. Ensure 100% compliance with all regulatory and code required inspections in each state where we operate.
- Safe and Reliable System. Ensure damage prevention rate at or below 3.75 damages per 1000 locates.

- Service Quality Indexes. Meet or exceed all SQI's in all jurisdictions.
- Customer focused, on-time appointments met. Appointments met in the field at least 95% of the time. Implement call ahead process across all jurisdictions.

Q: What do these goals demonstrate?

A: These goals demonstrate that Columbia's performance management process focuses on maintaining costs at or below budget, on safety, and on customer service. They also demonstrate that Columbia's customers receive significant value from achievement of the incentive plan goals.

Q: Please explain why the incentive compensation funding is based on certain financial goals.

A: Payment of incentive compensation also depends upon the availability of an incentive pool to fund that compensation. The availability of the incentive pool depends upon the financial health of the business unit and the overall corporation in the respective operating year. Therefore, the incentive pool is established where the corporate earnings-per-share and business unit earnings goals are met. Given that a fair percentage of total employee compensation is subject to the incentive compensation plans, it is necessary for corporate and business unit financial goals to be achieved to provide funding for employee incentive payments. However, even though the plan may be fully funded, employees may have their incentive award increased or decreased based upon achievement level of individual goals as outlined in their performance management worksheets. Achievement of individual goals by all employees drives overall company achievement in all measures including customer service, efficiency, and safety.

Q: Do you agree with Mr. Henkes' opinion on page 24 of his direct testimony that notes "these plans should be characterized as bonus or profit sharing plans that provide compensation that is clearly additive to the employees' total base compensation."?

A: No, I do not. Incentive compensation is an element of competitive total compensation in the labor market both within the utility industry and within the broader employer base. This is evidenced by a recent survey conducted by Hewitt Associates. The following is an excerpt from Attachment JFR-2, the Highlights and Trends section of The Hewitt Variable Compensation Measurement ("VCM") Survey:

> Variable pay plans continue to be a significant driver of most survey organizations' total compensation offerings. The Hewitt VCM survey continues to support the trend that companies are turning to variable pay as a means to attract, retain, and award performance while traditional merit increase budgets continue to remain at record low levels. The frequency of companies with at least one variable pay plan continues to increase since 1995. In 2008, a median 98 percent of total U.S. employees are eligible for at least one type of variable pay award, an increase from 89 percent in 2007.
>
> According to Hewitt's Salary Increase Survey, in 1994, 60 percent of U.S. companies indicated they had at least one broad-based variable pay plan in place. By 2008, 90 percent of U.S. companies had implemented a broad-based variable pay plan. (emphasis added)
>
> A typical mix of variable pay plans may include a business incentive plan with combined financial and operational performance criteria for staff functions.
>
> Business incentive plans are the most flexible type of variable pay plan in that they allow the combination of financial and operational performance measures that can be assessed at different levels of the organization. These plans consistently have been the most prevalent type of variable pay plan in VCM. Three-fourths (75%) of the surveyed companies reported to have at least one business incentive plan in place.

Therefore, to remain competitive in the labor market, it is important to provide incentive compensation as part of total compensation. If Columbia maintains a competitive base compensation, but does not provide incentive compensation, it follows that total compensation will lag the competition and employees will have larger total compensation opportunities at other employers providing competitive compensation inclusive of incentives. It also follows that if incentive compensation is removed from the total compensation package, then base salaries would need to be increased to remain competitive with the marketplace.

Q: On page 27 of Mr. Henkes' testimony, he recommends that uncollectible expense be based on a 5-year average rate. Do you agree with his opinion?

A: No, I do not.

Q: Please explain why you disagree with his opinion.

A: Columbia's test year level uncollectible rate of 1.410552% is lower than the rate Columbia expects for the rest of 2009 based on actual experience through June, 2009. The expected rate for 2009 is 1.668603%. Mr. Henkes notes in his testimony at page 27, "to assume that this very high rate will continue to be experienced in the rate effective period of this case, in my opinion, is unreasonable." He offers no evidence supporting this opinion. I believe, based on 2009 experience through June, it is unreasonable to assume the level will drop to the 1.094463% level he proposes any time soon.

Q: Is there another reason for disagreement with Mr. Henkes proposed uncollectible expense recovery?

A: Yes. On page 18 of Mr. Henkes direct testimony he makes an adjustment to revenues net of associated costs of gas of $197,963 to reflect normalized volumes on a 25-year basis instead of the 20-year basis that Columbia filed for in this case. He made no corresponding adjustment to operating revenue and expense for increased gas cost recovery revenue and expense associated with the increased volumes between the two bases of normalization on his attached Sch. RJH-5. Had he made the adjustment, gas cost recovery revenue would have been $819,261.51 higher ($112,563,472.84 - $111,744,211.33). Even more importantly, Mr. Henkes did not recognize the $1,017,225 ($197,963 + $891,262) increase in revenue on his schedule RJH-9 line 1 as an adjustment to revenue and therefore when he calculated uncollectible accounts on line 3 using his uncollectible net write-off rate he under-calculated uncollectible expense by $11,133.

Q: On page 30 of Mr. Henkes' testimony he recommends a 3-year rate case expense amortization period. Do you agree with this amortization period?

A: I agree that a 3-year rate case expense amortization period could be reasonable in the event Columbia's AMRP rider, Pension and OPEB mechanism ("POM") rider, Gas Cost Uncollectible Charge, and SFV rate design proposals are approved in this case. Approval of these proposals will mitigate the primary drivers of more frequent rate cases in the future.

Q: Mr. Henkes' recommends that NiSource Corporate Services Company business promotion services expenses be disallowed. Do you agree with his recommendation?

A: No, I do not.

Q: Please explain why you disagree.

A: First, Mr. Henkes draws a distinction between allocated and direct charges for these services, noting that expenses that are allocated should not be funded by ratepayers. NCSC employees may work on projects and tasks solely related to Columbia. Time spent in this regard is directly charged to Columbia. When these employees are working on tasks that may benefit more than one NiSource company they allocate their time. The cost to customers is reduced due to this sharing of costs that produce benefits common to more than one company. Therefore, both directly charged activities and allocated activities produce benefits to Columbia Gas of Kentucky customers.

Second, Mr. Henkes notes that there is no information in this case showing how and to what extent Columbia's customers benefit from NCSC's business promotion activities. As noted in Columbia's response to AG data request 2-22, "employees in this department provide cost analysis and information to customers regarding products and services." The cost analysis provided to existing and new customers is related to the following items: conversion from alternate fuels to natural gas, service requirements for new construction of homes and businesses, as well as comparisons of alternative fuels to natural gas. This cost analysis may lead to the addition of new customers which will provide a lower cost to the existing Columbia customers because each new customer connecting to natural gas service spreads the cost to serve over a larger customer base. The department conducts the cost-benefit studies using a model for new customer additions that are beyond 100 feet from Columbia's main. This calculation is used to determine what the customer may need to provide in terms of a contribution and/or line extension agreement in order to have service provided by Columbia. The department performs all the upfront work of collecting information and providing customers with information regarding having service established. This process ensures Columbia's existing customers do not take on more of the burden of the new load than is permitted.

The department also provides customers with information through letters and informational packets of what to expect when working with Columbia on their specific projects.

The department manages projects from application to installation by coordination of the application, communication with the customer, relaying information on installation of their service, notification of service line installation completion, gathering orders for meter installation, working through scheduling issues, working with the Columbia engineering department on information regarding feasibility to serve the customer.

The department also generates any agreements associated with projects and collects agreements and monies for proper processing. It also reviews existing customer agreements, processes checks for customer refunds and processes bills for customer deposits.

The department assists in setting up work orders and coordinating connections. Employees in the department assist existing customers who are adding natural gas appliances to their home or business to determine if their current facilities are adequate to serve their additional load requirements.

The department provides the new load requirements to engineering for capacity planning/decisions and to demand forecasting so that Energy Supply Services can make supply plans.

The department's employees work with customers to help resolve any issues or concerns about their gas bill or tariff provisions. They review customers' current situations and assist them to determine if they are on the appropriate rate.

Columbia's response to AG data request 2-22 also noted, "In addition, these employees spent a great deal of time educating consumers on energy efficiency and conservation, as well as natural gas safety which allows consumers/ratepayers to make educated choices regarding energy efficiency and conservation." Mr. Henkes indicates that Columbia has not explained why NCSC's business promotion services activities would include activities in the areas of energy efficiency, conservation, and natural gas safety. These discussions are around equipment efficiencies, natural gas efficiencies as compared to alternative fuels and conservation measures to reduce customer energy consumption. Employees also discuss with customers tax credits for energy efficient appliances and improvements to homes and provide information regarding energy efficiency programs offered. Customers are advised on safety matters, such as calling for utility line location prior to digging on their property, using the proper regulators on appliances if elevated pressure is needed, keeping meters 3 feet from door and window openings and 5 feet from an air conditioning units, as well as what to do if they smell gas, and how to avoid carbon monoxide problems.

Q: Do you agree with Mr. Henkes' opinion on page 36 of his testimony that the NiSource Corporate Services Company Supplemental Executive Retirement Plan ("SERP") expenses be disallowed?

A: No, I do not. The SERP is part of a total compensation concept. NiSource performs periodic market analysis for compensation and other benefits and believes that in order to retain and attract quality employees must be able to compete for talent on equal footing. Columbia believes that retaining and attracting quality employees will provide an ultimate benefit to the CKY customers.

Q: Do you agree with Mr. Henkes' adjustment to Depreciation Expense attachment REH-13?

A: No. I will discuss two issues that apply to Depreciation Expense: 1) Mr. Henkes eliminated Columbia's $29,477 adjustment for depreciation expense associated with CWIP stating it was done in accordance with previously established Commission policy. However, the CWIP plant in which Columbia has in its rate base in this case and the $29,477 of depreciation expense was calculated is CWIP that was actually in service by December 31, 2008. However, because of normal lags in paper work the plant had not been reclassified on Columbia's books at December 31, 2008. The Commission policy to which Mr. Henkes refers applies to CWIP plant that is under construction, but not yet in service. Columbia is not requesting recovery of depreciation expense for CWIP plant on Columbia's books that was not in service as of December 31, 2008. 2) In Columbia's response to data request number AG 1-60 parts 2 and 5, Columbia indicated depreciation expense calculated on four plant accounts was not correct on Schedule B-3.2. Those accounts were: Account 392.1 (filed for $146, corrected $0); Account 392.21 (filed for $33,983, corrected $8,724); Account 303.00 (filed for $0, corrected $2,478): and Account 303.30 (filed for $0, corrected $257,713). Mr. Henkes did not include any of the corrections in his depreciation expense adjustment in attachment RJH-13 but should have. In response to Columbia data request 67 to the AG, Mr. Henkes responded that he requested Mr. Majoros to reflect the depreciation expense corrections in the determination of the AG-recommended annualized plant depreciation expense and he assumed the corrections are reflected in Mr. Majoros' recommended depreciation expense number. A review of Mr. Majoros' response to PSC data request 5 a. to the AG would indicate these corrections were not included in his recommended depreciation expense amount.

Q: Do you agree with Mr. Henkes' adjustment to Property Tax attachment REH-14?

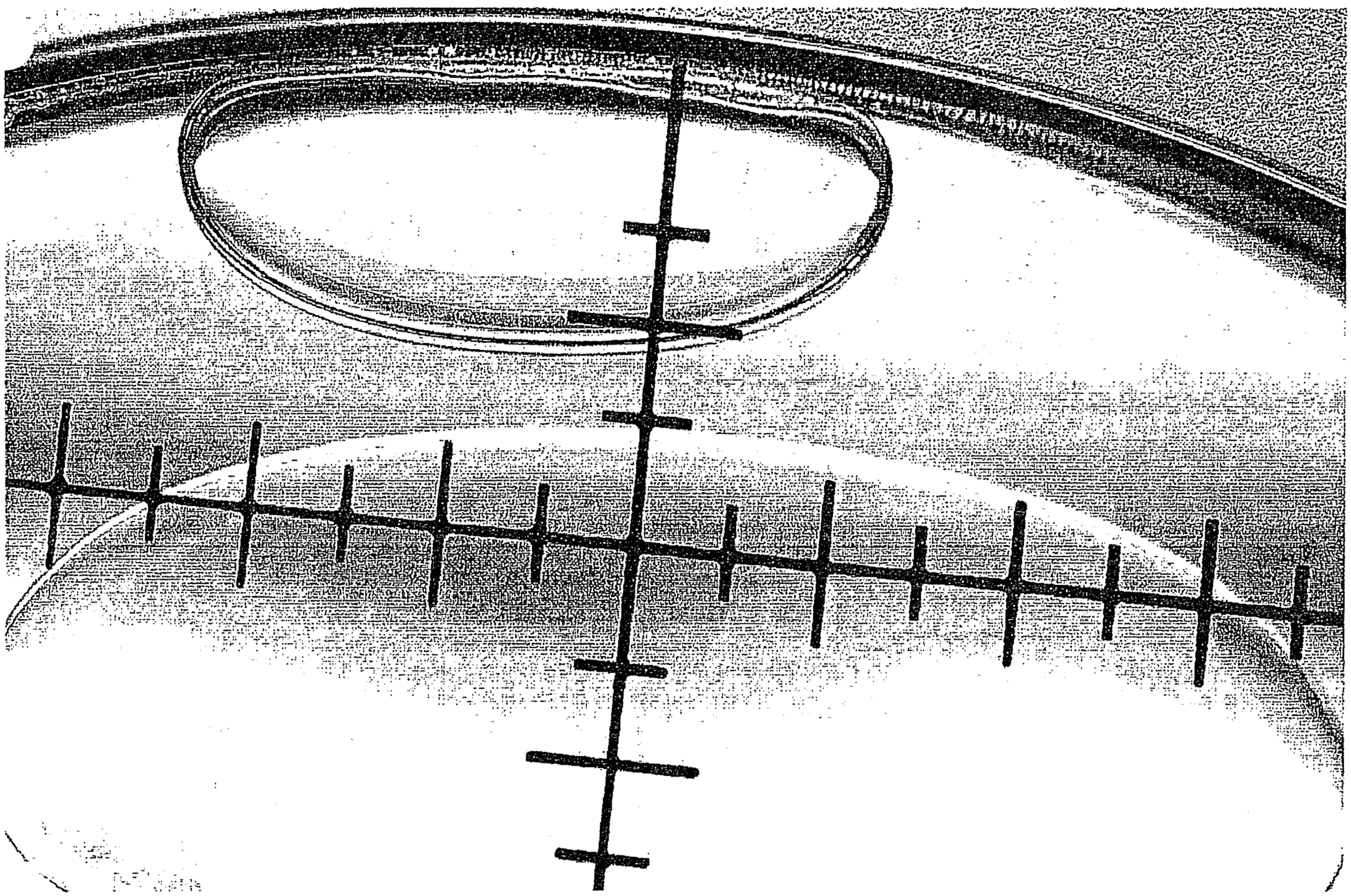
A: No. As shown on Columbia's updated response to Attorney General data request Set 1, number 60, a correction to the property tax adjustment on Schedule D-2.11 has been made to properly reflect the property tax pertaining to gas stored underground. The property tax is assessed on the value of storage as of December 31 each year and not on the 13 month average as shown in both Adjustment D-2.11 and Mr. Henkes' Sch. RJH-14. The December 31, 2008 value of storage on a per book LIFO basis is shown on WPB-5.1, Sheet 4 as $61,163,255. Therefore, the amount of property tax that should have been reflected for underground storage in Adjustment D-2.11 is $276,778 = ($61,163,255 x 37.9284% x 1.1931%) instead of $218,272 as shown on line 12. This is a property tax increase of $58,506. The proposed average storage valuation will not change the book valuation of storage used for property tax purposes. Applying this per books amount to Mr. Henkes' Sch. RJH-14 would yield an adjustment of $0 instead of the $(70,000) shown on Line 2d. Overall this is a change in expense of $128,506 = ($70,000 + $58,506) from the AG's position.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Hewitt

Variable Compensation Measurement™
The 2008 VCM™ Report–U.S. Edition



2008 Variable Compensation Measurement™ (VCM™) Results

Hewitt Consulting

September 2008

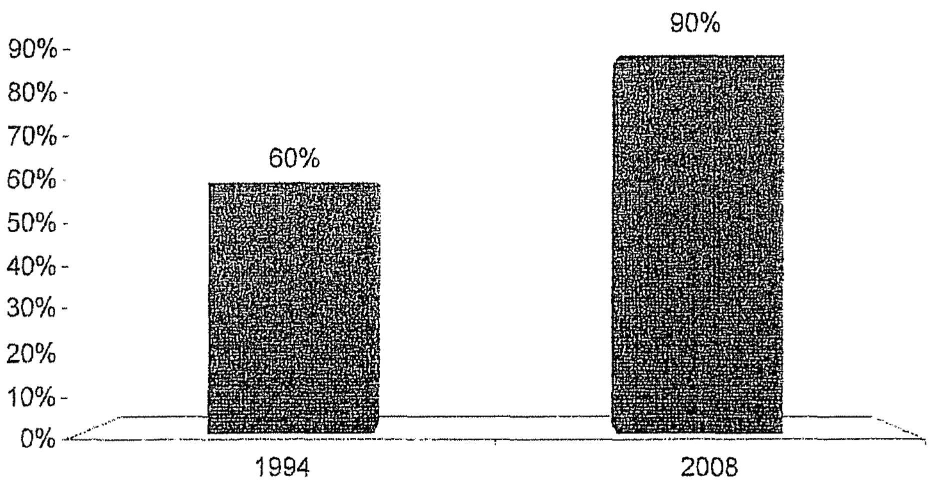
Highlights and Trends

Variable pay plans continue to be a significant driver of most survey organizations' total compensation offerings. The Hewitt VCM survey continues to support the trend that companies are turning to variable pay as a means to attract, retain, and award performance while traditional merit increase budgets continue to remain at record low levels. The frequency of companies with at least one variable pay plan continues to increase since 1995. In 2008, a median 98 percent of total U.S. employees are eligible for at least one type of variable pay award, an increase from 89 percent in 2007.

Prevalence of Variable Compensation

According to Hewitt's Salary Increase Survey, in 1994, 60 percent of U.S. companies indicated they had at least one broad-based variable pay plan in place. By 2008, 90 percent of U.S. companies had implemented a broad-based variable pay plan.

U.S. Companies With at Least One Broad-Based Variable Compensation Plan



Source: Hewitt 2008/2009 Salary Increase Survey Report.

Not only have more U.S. companies in the survey group introduced broad-based variable compensation in recent years, companies also have changed the look of their variable pay plans.

Organizations may have had one plan covering all employees in all locations and/or departments in recent years. However, these plans are now often being replaced by more customized variable compensation plans. Today, companies tend to design multiple plans for different employee groups. A typical mix of variable pay plans may include a business incentive plan with combined financial and operational performance criteria for staff functions. Stock option plans are often used to create an ownership mind-set and individual performance plans give managers the power to reward and retain their top performers.

Types of Variable Compensation Plans Prevalence

Since its inception in 1996, VCM has tracked the prevalence of the different types of variable pay. This chart depicts the plans in use by the companies in the VCM database for the last five years.

	Percent of Companies With Each Plan Type[1,2]				
	2004	2005	2006	2007	2008
Business Incentives—Plans with combined financial and/or operating measures for company, business unit, department, plant, and/or individual performance.	75%	74%	81%	85%	75%
Cash Profit Sharing Plans—Plans that make equal payment (as a flat dollar amount or percent of salary) to all or most employees based on organizational profitability.	18%	21%	15%	15%	12%
Individual Performance Plans—Plans whose payouts are based solely on individual performance criteria. Payout amount typically varies from one individual to another.	35%	33%	28%	23%	22%
Gain Sharing/Productivity Plans—Plans designed share a percent of cost savings of a group, unit, or organization. The gains are typically shared uniformly among all participants.	8%	7%	6%	6%	6%
Team Awards—Plans that provide incentives to individuals on a project or work team.	14%	9%	8%	6%	5%
Special Recognition Plans—Plans that are designed to recognize special individual or group achievements with small cash awards or merchandise.	51%	56%	53%	56%	54%
Stock Option Plans—Plans under which stock options are granted to employees below the executive level.	46%	37%	34%	40%	31%

[1] Percentages will total more than 100% since more than one response was provided by some participants.
[2] Table represents all plans currently implemented by participating companies. The following sections only include plans where participating companies provided data.

Business incentive plans are the most flexible type of variable pay plan in that they allow the combination of financial and operational performance measures that can be assessed at different levels of the organization. These plans consistently have been the most prevalent type of variable pay plan in VCM. Three-fourths (75%) of the surveyed companies reported to have at least one business incentive plan in place.

Business incentive plans can be seen as hybrids of more traditional types of variable compensation plans by linking different performance measures and aligning employees from different areas of the business with the same goals.

Gain sharing and cash profit sharing plans have not significantly changed in popularity over the last five years. These types of plans are the incentive approach of choice for certain business situations, e.g., a manufacturing plant with good measurement systems and substantial room for improvement in the production process might explore the viability of a gain sharing plan in their environment.

Special recognition awards are offered by more than half of the VCM participants. These awards are usually smaller in size than the payouts under other variable pay plans, and most often take the form of merchandise or cash. These plans commonly represent a separate layer of variable pay, since most employees who are eligible for a special recognition plan also are participants in another variable pay plan.

Individual performance plans decrease in prevalence slowed in 2008, with 22 percent of the VCM participants reporting having individual performance plans in place in 2008, from 23 percent in 2007. However, the decrease over the last five years is substantial, from 35 percent in 2004 to 22 percent in 2008. This decrease may be influenced by the increase in the prevalence of business incentive plans that include an individual performance component.

Over the last five years, the most significant decrease in prevalence can be observed for stock option programs. The expensing of stock options may be influencing the number of companies that offer stock options. The value delivered by these nonexecutive stock option plans varies widely. While some companies granted a nominal number of stock options as a recognition of accomplishing some corporate milestone (e.g., 50 shares to every employee at 50th anniversary of the company), others have adopted stock options as a critical component of their total compensation philosophy and granted substantial amounts to their top performers and key employees.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF PAUL R. MOUL ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

COLUMBIA GAS OF KENTUCKY, INC.
Rebuttal Testimony of Paul R. Moul
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PREPARED REBUTTAL TESTIMONY OF PAUL R. MOUL

INTRODUCTION

Q: Please state your name, occupation and business address.

A: My name is Paul R. Moul and I am Managing Consultant of the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q: Mr. Moul, have you previously submitted direct testimony in this proceeding?

A: Yes. My direct testimony was submitted with the Company's case-in-chief on May 1, 2009.

Q: What is the purpose of your rebuttal testimony?

A: Columbia Gas of Kentucky ("Columbia of Kentucky" or the "Company") has requested that I comment on and rebut the testimony presented by Dr. J. Randall Woolridge, a witness appearing on behalf of the Office of the Attorney General ("OAG"), and Ms. Nancy Brockway, a witness appearing on behalf of American Association of Retired Persons ("AARP"), concerning the limited issue of the risk implications of the Company's rate design proposal.

Q: Please identify the principal areas of controversy concerning the rate of return issue in this proceeding.

A: The capital structure ratios, cost of long- and short-term debt, and rate of return on common equity represent the areas of dispute in this case. Dr. Woolridge has proposed an alternative capital structure developed without regard to the rate base upon which the

Company will realize a return and the Company's actual amount of short-term debt. Dr. Woolridge has also ignored the cost associated with the additional amount of debt that he assumed for the long-term debt ratio that he has proposed. Further, Dr. Woolridge has proposed to use the intercompany effective cost of short-term debt for December 2008, which is less than what could be expected for the rate effective period. Finally, Dr. Woolridge has proposed a totally inadequate rate of return on the Company's common equity that does not come close to the types of returns investors expect or require.

CAPITAL STRUCTURE AND COST OF DEBT

Q: How does your capital structure proposal differ from that proposed by Dr. Woolridge?

A: There are several key areas where they differ. I have used the Company's actual thirteen-month average amount of short-term debt for the test year, along with the Company's actual test year rate base to develop the capital structure ratios for this case. This approach will synchronize the capital structure ratios with the Company's rate base on which it will earn a return. On the other hand, Dr. Woolridge develops hypothetical capital structure ratios from his proxy group that already includes short-term debt, which ignores the Company's actual amounts of short-term debt. In so doing, he has imputed more combined short- and long-term debt than is appropriate for the Company in this case. Indeed, if he had developed his hypothetical capital structure ratios without regard to short-term debt, Dr. Woolridge would have arrived at essentially the same ratios that I proposed for the Company in this case. This is because his average quarterly capitalization ratios for his proxy group are 44.33% long-term debt and 55.67% equity, which include a minor amount of preferred stock. These ratios confirm the reasonableness of the 45% long-term debt and 55% common equity ratios that I employed to compute the Company's capital structure ratios using permanent capital excluding short-term debt.

Q: Has Dr. Woolridge reflected the additional cost associated with the amounts of long-term debt that would be outstanding based on his capital structure proposal?

A: No. Both Dr. Woolridge and I have used a long-term debt ratio (42.56% in my case and 44.35% in his case) that exceeds the Company's actual long-term debt ratio of 40.63%. To realize the long-term debt ratios proposed by Dr. Woolridge and me, the Company would need to issue additional amounts of long-term debt. In my case, the additional amount of long-term debt would be approximately $5.313 million, and in the case of Dr. Woolridge, the additional amount of long-term debt would be approximately $8.569 million. There is an interest cost associated with these additional amounts of long-term debt. In my proposed rate of return, I reflected the additional cost associated with the incremental amount of long-term debt. Dr. Woolridge ignored this cost because he erroneously mismatched the Company's actual long-term debt cost with a long-term debt ratio that contains an extra $8.569 million of debt. His proposed embedded cost of debt is inappropriate.

Q: Dr. Woolridge also used the Company's actual cost of short-term debt for December 2008 in his proposed weighted average cost of capital. Is this appropriate?

A: No. We are calculating the Company's weighted average cost of capital that will reflect capital costs for the rate effective period. The proposal by Dr. Woolridge regarding the cost of short-term debt is backward looking. Instead, we should use the cost that reflects expected conditions for the rate effective period, which begins on November 1, 2009.

The Company obtains its short-term debt from the NiSource Money Pool, which obtains its funds at a rate of 57 basis points above LIBOR (London Interbank Offered Rate). At this time, short-term interest rates are artificially low due to monetary policies instituted by the FOMC (Federal Open Market Committee) that are intended to deal with the global financial crisis and the economic recession. As these issues are resolved, interest rates will move higher, and the yields on Treasury obligations have already moved up significantly as shown on page 2 of Exhibit JRW-11 provided by Dr. Woolridge. The August 1, 2009 Blue Chip Financial Forecast projects the LIBOR increasing from 0.7% in the first quarter of 2010 to 1.6% by the fourth quarter of 2010, or the end of the first year that new rates obtained from this case will be effective. As a result, the Company's cost of short-term debt should be at least 2.17% (1.6% + 0.57%) using the Blue Chip forecast for the fourth quarter of 2010. Longer-term, the Blue Chip issue dated June 1, 2009 shows an average LIBOR rate of 4.1% covering the years 2011-2015. In that case, the short-term debt cost rate would be 4.67% (4.1% + 0.57%).

COST OF EQUITY

Q: What are the principal deficiencies in the cost of equity analyses presented by Dr. Woolridge?

A: Dr. Woolridge has proposed a considerably lower rate of return on common equity than my analysis has indicated. The major differences concerning the cost of equity involve: (i) the return level that will be acceptable to the financial community, (ii) the selection of proxy group companies to measure the cost of equity, (iii) the determination of a reasonable Discounted Cash Flow (DCF) cost rate, (iv) whether an adjustment to the DCF is necessary when applied to a capital structure measured at book value, (v) a flotation cost adjustment, (vi) the extent to which other methods of determining the cost of equity provide a reasonable measure of the appropriate cost of common equity, and (vii) whether adjustments are necessary to the Company's cost of equity due to its rate design proposal. I believe that the rate of return on common equity proposed by Dr. Woolridge is inadequate to provide the Company with the opportunity to earn its cost of capital during the rate effective period.

Q: What has caused this to happen?

A: Dr. Woolridge has based his cost of equity proposal principally on the DCF model. He has supplemented his DCF findings with the CAPM. However, Dr. Woolridge calculates a CAPM result of 7.4%, which is totally unrealistic. Rather than acknowledge the infirmities of his CAPM application, Dr. Woolridge explains that he has moved toward the top of his range (i.e., 7.4% to 9.40%) in selecting a 9.25% return on equity due to current volatile market conditions. I am somewhat perplexed by his proposal here because he states that he is using the upper end of the range, which would be 9.40% and not 9.25%. These various proposals are prior to his 0.25% reduction to the cost of equity to reflect his perception of the risk implications of the Company's rate design proposal.

The specific infirmities of his analyses include:

- Dr. Woolridge's application of a backward-looking DCF that reflects undue emphasis on historical growth rates, especially on variables other than earnings.
- The failure to adjust the market determined cost rates (i.e., DCF and CAPM) to reflect the far different (i.e., higher) financial risk associated with a book value capital structure.
- Failure to recognize flotation costs as a component of the cost of equity.
- CAPM results by Dr. Woolridge that do not come close to capturing investor expectations.
- Inadequate consideration of the results generated by the Risk Premium and Comparable Earnings methods.

Q: How would the financial community react to the Commission's acceptance of the cost of equity proposed by Dr. Woolridge?

A: The financial community would be extremely concerned, if not shocked, if the Commission set the Company's cost of equity at the level proposed by Dr. Woolridge.

Q: Are there objective indications of the level of returns expected by investors which shows that the proposed cost of equity by Dr. Woolridge is much too low?

A: Yes. According to the Value Line report dated June 12, 2009, the natural gas utility industry is forecast to earn the following returns:

2009	10.0%
2010	10.5%
2012-14	11.0%

We can see that the returns that investors expect display an increasing trend going forward. The costs of equity proposal by Dr. Woolridge runs counter to these expectations.

Q: Are those returns based on market values or book values?

A: The returns listed above are book value returns for the industry generally. Value Line also publishes market value returns for each company that it follows. Listed below are the market value returns that Value Line is providing to investors.

	Annual Total Return		
Company	High	Low	Midpoint
AGL RESOURCES INC (NYSE:AGL)	20%	12%	16.0%
ATMOS ENERGY CORP (NYSE:ATO)	16%	9%	12.5%
LACLEDE GROUP INC (NYSE:LG)	19%	12%	15.5%
NICOR INC (NYSE:GAS)	17%	10%	13.5%
NORTHWEST NAT GAS CO (NYSE:NWN)	14%	9%	11.5%
PIEDMONT NAT GAS INC (NYSE:PNY)	18%	11%	14.5%
SOUTH JERSEY INDUSTRIES INC (NYSE:SJI)	13%	5%	9.0%
SOUTHWEST GAS CORP. (NYSE:SWX)	19%	12%	15.5%
WGL HOLDINGS INC (NYSE:WGL)	13%	8%	10.5%
Average			13.2%

We can see that the 9.25% cost of equity proposed by Dr. Woolridge, prior to his downward adjustment is out of step with the returns investors expect. The wide dissemination of Value Line and frequent references to it as a source of information (including by Dr. Woolridge) show that investors consider the data when formulating their expectation. The process that we use to measure the cost of equity in proceedings such as these involves replicating the deliberative process of investors when they decide to purchase, hold, or sell a stock. So if Value Line represents an investor-influencing source of information, then it is relevant to this proceeding and it shows that Dr. Woolridge's proposed cost of equity is much too low. As such, based upon the Value Line data, a reasonable investor expectation would be within the range of approximately 11% to 13%.

COMPARABLE COMPANIES

Q: Have proxy groups of companies been employed in this case to determine the Company's cost of equity?

A: Yes. Dr. Woolridge and I have used proxy groups of companies to measure the cost of equity for Columbia of Kentucky. Dr. Woolridge and I have used many of the same companies in our respective proxy group. However, Dr. Woolridge has erroneously deleted New Jersey Resources from his groups and, in addition, he included Laclede, NICOR, and Southwest Gas in his group of natural gas distribution companies. His reasoning for ignoring New Jersey Resource is based on his mistaken belief that its low percent of its revenue from its gas utility disqualifies it from the proxy group. But the revenue percentage is the wrong criteria for including a company in the proxy group.

Q: Please explain why the percentage of revenues devoted to utility operations is an

inappropriate criteria for excluding New Jersey Resources from the proxy group.

A: For natural gas companies, revenues cannot be used for selection purposes because the margins on other business segments are generally dissimilar to the gas distribution business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the small margins associated with this business segment. Operating income would also be inappropriate for this purpose because of the margin issue discussed above. In addition, some non-regulated business segments may incur losses due to start-up, or other reasons, that can distort the percentage calculations. The correct screening criterion is the percentage of gas assets because it best describes the amount of capital that a firm devotes to each business segment.

Q: What are the business segment data for New Jersey Resources?

A: Those data are presented below:

New Jersey Resources Corporation

Year Ended September 30, 2008	Revenue from External Customers	Segment Profit: Net Income	Segment Assets
		(in millions)	
Gas Operations	$1,078.8	$42.5	$1,762.0
Percent	**28.27%**	**37.29%**	**67.11%**
Total Consolidated	$ 3,816.2	$ 113.9	$ 2,625.4

From the data shown above, New Jersey Resources is a valid candidate for inclusion in the proxy group because 67% of its assets are devoted to gas utility operations.

Q: Please comment on the inclusion of Laclede Group, NICOR, Inc. and Southwest Gas in the proxy group used by Dr. Woolridge.

A: Southwest Gas should not be included in the proxy because it is geographically remote to Columbia of Kentucky, and serves an arid region of the U.S. Further, Laclede Group should be excluded from the group because it does not have a revenue decoupling mechanism. At the time that I assembled my proxy group, NICOR also did not have revenue decoupling. But since then, the ICC has provided NICOR with 80% SFV rate design, which would now qualify it for inclusion in the proxy group.

DISCOUNTED CASH FLOW

Q: Dr. Woolridge and you have used the DCF model to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A: In my view, the use of more than one method provides a superior foundation for the cost of equity determination. This is particularly true today given the recent wide swings in share values and the overall financial market uncertainty experienced during the financial crisis. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.).

Q: What form of the DCF model has been employed in this case?

A: The constant growth form of the DCF model has been used by Dr. Woolridge and me. It must be recognized, however, that this form of the DCF method employs assumptions which are simply not realistic. For example, according to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same constant rate absent any change in dividend payout and price-earnings multiple. There is no evidence that these conditions actually prevail in the equity markets.

DCF DIVIDEND YIELD

Q: Do you have any comments regarding Dr. Woolridge's criticism of your dividend yield calculation?

A: Yes. Dr. Woolridge complains that my dividend yield is overstated due to some unexplained failure to properly annualize the quarterly dividend amount and the compounding associated with the quarterly payment of dividends. But here, Dr. Woolridge has created a straw-man issue regarding my calculation of the dividend yield. As shown on pages E-5, E-6, and E-7 of Appendix E that accompanies my direct testimony, the 4.25% dividend yield derived from the formula D_0/P_0 (1 +.5g) which is embraced by Dr. Woolridge (see page 1 of Exhibit JRW-10) produces virtually the same dividend yield that reflects quarterly compounding (i.e., 4.26%). The difference is just one basis point. As such, the testimony of Dr. Woolridge in this regard is a "tempest in a teapot" and should be ignored.

DCF GROWTH RATE

Q: As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A: The theory of the DCF holds that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share and dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be emphasized. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (another key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations (see pages E-7 through E-11 of Appendix E that accompanies my direct testimony. Finally, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model is forecasts of earnings per share growth.[1] For these reasons, earnings per share forecasts must be given primary weight.

Q: Dr. Woolridge has questioned the reliability of analysts' forecasts of earnings per share growth in the DCF model. Do you agree?

A: No, I do not. And the direct testimony of Dr. Woolridge also does not seem to share this concern. Indeed, Dr. Woolridge uses analysts' forecasts extensively in his DCF analysis.

[1] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

Q: Do you agree with Dr. Woolridge's view that analysts' forecasts of earnings per share contain some form of bias?

A: I find inadequate support for this assertion. With the final judgment entered on October 31, 2003 in the Global Research Analyst Settlement ("GRAS")[2], which resolved the equity research analysts practices at major investment banks that had been accused of conflicts of interest, Wall Street firms have separated their research and investment banking services. Hence, the criticisms by Dr. Woolridge are out-of-date. I find Dr. Woolridge's criticism of analysts' forecasts somewhat perplexing because he provides extensive evidence of analysts' forecasts (see pages 5 and 6 of Exhibit JRW-10) in his DCF analysis. I also do not understand why Dr. Woolridge would have difficulty accepting analysts' forecasts because the Claus and Thomas study, included as his first entry under the heading "Ex Ante Models (Puzzle Research)" on page 5 of Exhibit JRW-11, used analysts' earnings forecasts taken from I/B/E/S, now part of Thomson Financial that Dr. Woolridge reports as the Yahoo/First Call growth estimates (see page 6 of Exhibit JRW-10). Moreover, it matters not what Dr. Woolridge may think about the analysts' forecasts. Rather, what is important is what investors actually use in their decisions regarding the purchase, sale or holding of stocks. That is to say, even if there were some bias in the forecasts which suggested that some downward adjustment might be appropriate, the price of stock would likewise require a downward adjustment to remove the influence of the same bias that is reflected in the price that was established with the actual analysts' forecasts. The bottom line is that the growth rate must be

[2] SEC v. Bear, Stearns & Co., Inc., No. 03 Civ. 2937, 2003 U.S. Dist. LEXIS 19359 (S.D.N.Y. Oct. 31, 2003)

synchronized with the price that investors establish when valuing a stock. Otherwise, the DCF result would be misspecified, which is the case with Dr. Woolridge's result.

Q: Dr. Woolridge has also provided dividends per share growth rates published by Value Line. Are these growth rates useful in the DCF?

A: No. The Value Line forecast growth rates of 2.5% in dividends per share are clearly outliers as compared to other measures of growth (i.e., Yahoo/First Call, Zacks, and Reuters). The reason dividends per share growth is so low is that the dividend payout ratios are forecast to decline. This is shown below based on the Value Line data.

Company	2008	2009	2010	2012-14
AGL Resources, Inc.	60%	61%	59%	57%
Atmos Energy Corporation	65%	64%	62%	56%
Laclede Group, Inc.	56%	49%	60%	55%
Nicor Inc.	71%	70%	66%	63%
Northwest Natural Gas Co.	59%	55%	58%	58%
Piedmont Natural Gas Company	69%	69%	67%	62%
South Jersey Industries, Inc.	49%	49%	50%	50%
Southwest Gas Corporation	63%	58%	54%	50%
WGL Holdings, Inc.	57%	57%	58%	58%
Average	61%	59%	59%	57%

Q: Dr. Woolridge also appears to have considered, and perhaps to have given some weight to, historical growth rates in earnings, dividends, and book value. Please comment.

A: History cannot be ignored. However, in developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance.

Q: Did Dr. Woolridge also consider retention growth?

A: Yes. However, the retention growth formula was misapplied on page 5 of his Exhibit JRW-10. Those misapplications are discussed below.

Q: Apart from these theoretical deficiencies, has Dr. Woolridge properly determined retention growth?

A: No. Dr. Woolridge has relied upon the Value Line forecasts of year-end, rather than average, book values to calculate his return on book value returns. It is necessary to convert those figures from year-end to average book common equity. The failure to do so creates a downward bias in the results because, assuming some retention growth, the average book value will be less than the year-end book value. In fact, when the FERC employs these data, it adjusts the year-end returns to derive the average yearly return. Generally speaking, this adjustment would increase the retention growth rate. In calculating his retention rates, Dr. Woolridge relied upon the Value Line forecasts of the "return on equity." These returns are calculated with year-end values, rather than average book values. Value Line defines "return on equity" as follows:

> Percent Earned Common Equity – net profit less preferred dividends divided by common equity (i.e., net worth less preferred equity at liquidation or redemption value), expressed as a percentage. See Percent Earned Total Capital.

Without an adjustment to convert the Value Line forecast returns from year-end to average book values, there is a downward bias in the results. This is because with an increasing book value driven by retention growth, the average book value will be less than the year-end book value. For that reason, the Federal Energy Regulatory Commission ("FERC") adjusts the year-end returns to derive the average yearly return, using the formula 2 (1 + G) / (2 + G) (see 92 FERC ¶ 61,070). Generally speaking, this adjustment increases the retention growth rate.

Q: Has Dr. Woolridge included external financing growth in his internal growth analyses?

A: No. This omission results in a further downward bias in his growth rate analysis. Forecasts by Value Line indicate that future growth from external stock financing will add to the growth in equity. This would result in an internal/external growth rate higher than that developed by Dr. Woolridge.

Q: What growth rate would be indicated using the data assembled by Dr. Woolridge using earnings forecasts?

A: Using the data presented on page 6 of Exhibit JRW-10, the growth rates are 5.06% by Yahoo/First Call, 5.3% by Zacks, and 5.3% by Reuters. The average of the forecasts by these services is 5.22% (5.06%. + 5.3% + 5.3% = 15.66% ÷ 3)

Q: How would the use of these analysts' forecasts of earnings growth impact the DCF

employed by Dr. Woolridge?

A: The DCF result would be:

Discounted Cash Flow (DCF)	D_0/P_0	*x*	*(1+0.5g)*	+	*g*	=	*k*
Woolridge Gas Group	4.50%	x	1.02610	+	5.22%	=	9.84%

LEVERAGE ADJUSTMENT

Q: Please respond to the Mr. Woolridge's criticism of your leverage adjustment.

A: As in many (but not all) prior cases, I have proposed an adjustment to reflect the difference in risk attributed to changes in leverage that occur when the book value capital structure, rather than the market value capital structure, is used to compute the weighted average cost of capital. This modification to the DCF model must be recognized in order to make the DCF results relevant to the book value capital structure.

Q: Is Dr. Woolridge's challenge to your leverage adjustment well founded?

A: No. I am somewhat surprised by Dr. Woolridge's challenge to my leverage adjustment. In the book that he co-authored, there is a clear preference for using the market capitalization for valuation purposes. There it is stated:

> Market professionals always use the market value of common stock when they examine the capitalization of the corporation. As we will see in valuation examples, the market value of common stock sometimes bears little relationship to its book value. Stock prices are readily available.[3]

Q: Dr. Woolridge contends that in the recent Aqua Pennsylvania rate case the

[3] Gray, Gary, Cusatis, Patrick J., Woolridge, Randall J. Streetsmart Guide to Valuing a Stock: The Savvy Investor's Key to Beating the Market, Second Edition. New York: McGraw-Hill Companies (2004)

Pennsylvania Public Utility Commission ("PPUC") did not include a leverage adjustment. Please respond.

A: The fact that the PPUC declined to use the leverage adjustment in the Aqua Pennsylvania case does not invalidate its use. Rather, the PPUC merely indicated that the adjustment was optional. The PPUC did not repudiate the leverage adjustment, but instead arrived at an 11.00% return on equity for Aqua Pennsylvania by providing a separate return increment for management performance. Just like an increment for management performance is not used in all rate case decisions, so too the PPUC seems to be taking a similar approach to the leverage adjustment.

Q: Do you have any additional comments regarding Dr. Woolridge's attack on the leverage adjustment?

A: Yes. Dr. Woolridge has not disputed the fact that there is less financial risk associated with a 68.79% (market price-based) equity ratio than there is with a 55.24% (book value-based) equity ratio for my Gas Group (see page E-12 of Appendix E that accompanies my direct testimony. Dr. Woolridge has acknowledged in his book that the market value of common equity is the only relevant item for professional investors. Because financial risk increases when the common equity ratio is lower, the cost of equity must likewise increase.

Q: Dr. Woolridge also claims that the leverage adjustment will serve to increase the return for companies with high market-to-book ratios and decrease the returns for

companies with low market-to-book ratios. Please respond.

A: Dr. Woolridge neglects to mention that, all else being equal, a company with a higher market-to-book ratio will have a lower dividend yield. Essentially, the leverage adjustment adds stability to the simple DCF returns. Further, there are many factors that impact the leverage adjustment, including changes in the market capitalization and book capitalization, the components of the yield and growth (noted above), and the overall level of capital costs as revealed by the marginal cost of debt and preferred stock. Although rare, the formulas that I use to compute the leverage adjustment could actually produce a lower adjustment with a higher differential between the market capitalization and book capitalization.

Q: What DCF results would be produced when the leverage adjustment is incorporated into the data presented by Dr. Woolridge?

A: The results that I reported previously in my rebuttal testimony using data from Dr. Woolridge require the leverage adjustment. Their DCF results would become:

	Simple Yield (D_1/P_0) plus Growth (g)	Leverage Adjustment	Ratesetting Cost of Equity
Dr. Woolridge	9.84%	0.62%	10.46%

FLOTATION COSTS

Q: Dr. Woolridge has failed to modify his DCF results for the flotation costs and, he has criticized your testimony for reflecting those costs. Has the omission of this

adjustment resulted in an understatement of the required rate of return on common equity?

A: Yes. I should note that Dr. Woolridge's position concerning flotation costs is inconsistent with the Value Line forecasts that show that natural gas companies will be issuing new common stock in the future. Moreover, the industry has historically issued significant quantities of new equity (see Attachment PRM-10) that accompanies my direct testimony.

As to the specific points raised by Dr. Woolridge, regarding item (1) the relative market-to-book ratio has no bearing on whether a flotation cost adjustment is proper. These costs are incurred regardless of the relationship of the stock price to book value. Concerning item (2), essentially, Dr. Woolridge has repeated his position contained in his item (1). As to item (3), the reason that the underwriting spread is retained by the investment bankers necessitates its inclusion in flotation cost adjustment. This is because the utility can only invest the net proceeds received from a stock offering in its rate base. That is to say, the rate base investment from a common stock offering can only be made with the net proceeds and not the price of stock paid by investors. As to point (4), brokerage fees paid by investors to transact a purchase or sale of stock are entirely irrelevant to the issue. It is only the amounts realized by the utility after the impact of the underwriting spread and out-of-pocket expenses that affects the net proceeds that are available to invest in rate base.

RISK PREMIUM METHOD

Q: Do you believe the Risk Premium method provides significant evidence of the cost

of equity?

A: Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity. So, while Dr. Woolridge declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach which provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk.

Q: Do you have any comments concerning Dr. Woolridge's criticism of the risk premium approach?

A: Yes. As a preliminary matter, Dr. Woolridge claims that the yield on A-rated public utility bonds in my risk premium cost rate is overstated because the current yield is less than 6.0%. The fact is that the range in monthly yields on A-rated public utility bonds has been 5.97% to 7.60% during the past twelve months. And, the average monthly yield was 6.57% for the past twelve-months, 6.31% for six-months, and 6.22% for the past three-months.

Q: Please continue with your response to Dr. Woolridge's specific criticisms of your risk premium approach.

A: Concerning his first point on page 75, Dr. Woolridge seems to imply that use of the base yield in my risk premium analysis that includes A-rated public utility bonds is not correct. He attributes this in part to interest rate risk and default risk that are reflected in the yields on A-rated public utility bonds. These are invalid criticisms because common stock investors are faced with these same risks. Moreover, if the compensation for these risks were removed from the yield on A-rated public utility bonds, then the resulting risk premium would be larger when computed from a smaller base yield.

Dr. Woolridge's other criticisms of the historical relationship between stock and bond returns are invalid because: (1) common stock investors are subject to changing levels of interest rates because a primary determinant of the cost of equity is the level of interest rates (especially for utility stocks), and (2) the credit risk associated with a company's bonds is also a major concern for common stock investors (e.g., default on a company's bonds would adversely affect the common stockholders).

Q: Please address the alphabetic medley of criticisms listed by Dr. Woolridge on pages 77 to 85 of his direct testimony.

A: Most of these require only a brief response. As to item (A), (biased historical returns) the capital losses concerning historical bond returns were non-existent for long-term government bonds (used by Dr. Woolridge as a proxy for bond yields). Over the period 1926-2008, capital appreciation (rather than capital losses) was: 0.3% as the geometric mean and 0.6% as the arithmetic mean. Hence, his claim of losses is not correct. Dr. Woolridge also does not identify the magnitude of any difference between the published yield and investor expected returns on bonds. With bond portfolio immunization strategies, a desired rate of return can be achieved over a fixed investment horizon when the duration of a bond portfolio equals the investment horizon. Strategies such as these points to the extremely high probability of realizing expected returns on public utility bonds from issuance to maturity. Consequently, Dr. Woolridge's reasoning provides no basis to reject my risk premium approach.

As to item (B) (the arithmetic vs. geometric mean returns), Dr. Woolridge criticizes my use of arithmetic means in applying the risk premium method. However, as stated in the 2003 Yearbook published by Ibbotson Associates:

> The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for forecasting, discounting, and computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount his expected (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will, therefore, require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit his capital to the investment.

In the 2006 Yearbook, Ibbotson added:

> A simple example illustrates the difference between geometric and arithmetic means. Suppose $1.00 was invested in a large company stock portfolio that experiences successive annual returns of +50 percent and -50 percent. At the end of the first year, the portfolio is worth $1.50. At the end of the second year, the portfolio is worth $0.75. The annual arithmetic mean is 0.0 percent, whereas the annual geometric mean is -13.4 percent. Both are calculated as follows:

$$r_A = \frac{1}{2}\ (0.50 - 0.50) = 0.0,\ \textit{and}$$

$$r_G = \left[\frac{0.75}{1.00}\right]^{\frac{1}{2}} - 1 = -0.134$$

> The geometric mean is backward-looking, measuring the change in wealth over more than one period. On the other hand, the arithmetic mean better represents a typical performance over single periods.
>
> In general, the geometric mean for any time period is less than or equal to the arithmetic mean. The two means are equal only for a return series that is constant (i.e., the same return in every period). For a non-constant series, the difference between the two is positively related to the variability or standard deviation of the returns. For example, in Table 6-7, the difference between the arithmetic and geometric mean is much larger for risky large company stocks than it is for nearly riskless Treasury bills.

As to item (C) (the large error in measuring the equity premium using historical returns), Dr. Woolridge points to the relatively high standard deviation of the historically measured risk premium as an indication of possible forecasting error. But, he misinterprets the relatively high standard deviation. Rather, the relatively high standard deviation is a reflection of the basic riskiness of common stocks. Since common stocks are more risky than bonds or other low risk investments, then the standard deviation should be relatively high, because common stocks provide more uncertain returns as compared to more certain returns for lower risk bonds. If as Dr. Woolridge asserts, the common equity risk premium is unreliable because the standard deviation is relatively high, then he is repudiating the basic riskiness of common stocks.

As to item (D) (unattainable and biased historical stock returns), with the proliferation of stock-index mutual funds and exchange-traded funds ("ETF") that are designed to replicate the returns on major indexes, the overall market returns are attainable. While there may be transaction costs associated with both stock-index mutual funds (which are minimal for low cost managers, such as The Vanguard Group) and ETFs (which can be purchased and sold through discount on-line brokerage accounts), Dr. Woolridge's criticisms are misplaced.

As to item (E) (company survivorship bias), the survivorship issue is not a valid criticism because the historical returns contain the results of the companies that comprised the index in each year. That is to say, as companies entered and exited the index, the market performance in each year reflected the companies in the index each year. Obviously, Microsoft Corporation had no impact on the S&P 500 return in 1960, nor does Nash-Kelvinator Corporation impact the returns of the S&P 500 in 2008. But, these companies did provide returns to investors in the years that they were included in the index.

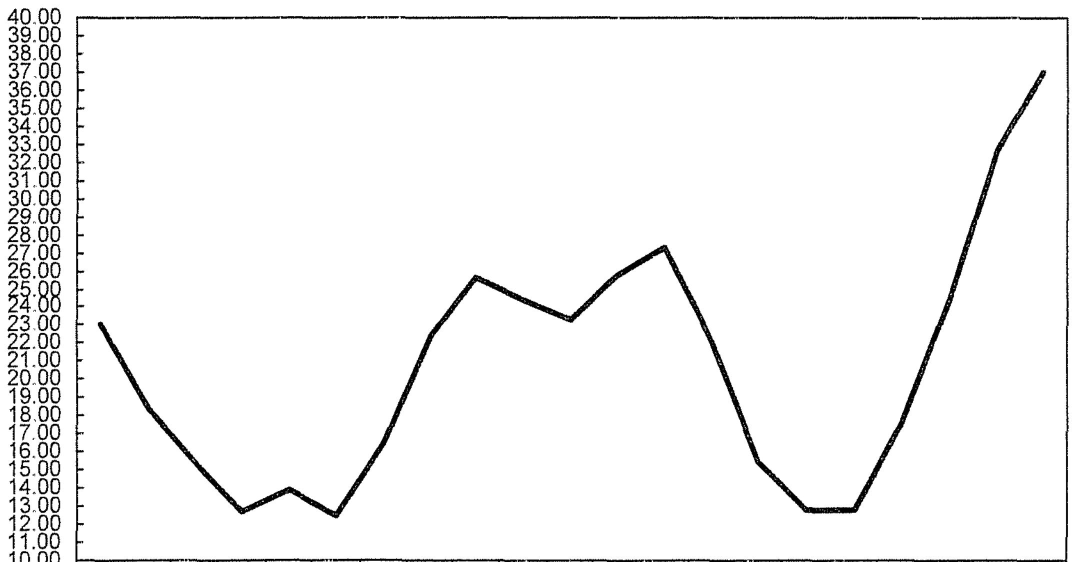
As to item (F) (The "Peso Problem" – U.S. stock market survivorship bias), Dr. Woolridge provides no quantification of the impact of the "peso problem" on the historical return. Just as higher than expected returns may have been experienced in the past, so too lower than expected returns also were experienced. Further, the possibility of "highly improbable returns" (e.g., positive or negative) is the reason that long time series are used in the risk premium analysis.

Q: Dr. Woolridge devotes a significant portion of his testimony to the proposition that

current market conditions are different than the past and the risk return relationship has changed in recent years, i.e., his items (g) and (h). Does the recent stock market variability suggest that Dr. Woolridge's arguments are not compatible with today's market?

A: Yes. Stock market variability can be observed from the Chicago Board Options Exchange ("CBOE") Volatility Index (i.e., "VIX"). The VIX is based on real-time prices of options on the S&P 500 Index, and is designed to reflect investors' consensus view of future (30-day) expected stock market volatility. The VIX is used as a measure of the risk associated with common stocks. The historical performance of the VIX is shown below.

CBOE Volatility Index®



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2009
VIX	23.06	18.37	15.43	12.68	13.94	12.42	16.47	22.37	25.60	24.36	23.30	25.77	27.28	21.99	15.48	12.81	12.81	17.54	24.37	32.69	36.99

The graph shown above indicates the yearly average of the VIX since 1990. The volatility of the stock market is today significantly higher than in the past several years. Given the performance of the VIX, there has been no shrinkage in the equity risk premium because risk has increased in recent years.

Q: Please respond to Dr. Woolridge's testimony concerning your proposed risk premium.

A: Notwithstanding Dr. Woolridge's testimony, I have taken a balanced approach by utilizing a 6.23% premium for the S&P Public Utilities, which is between the lowest and the highest premiums. The periods that I used, 1974-2007 and 1979-2007, experienced higher interest rates than did the longer historical period presented, resulting in a lower premium.

CAPITAL ASSET PRICING MODEL

Q: Do you have concerns regarding the application of the CAPM by Dr. Woolridge?

A: As a preliminary matter, Dr. Woolridge produced a 7.4% CAPM result that is simply not credible. This is especially true in the circumstance where the yield on Baa rated public utility bonds were 6.87% in July 2009. The cost of equity simply must be higher than the cost of debt by a meaningful margin, which is not the case with Dr. Woolridge's CAPM. His CAPM result is simply out of the ballpark. Dr. Woolridge's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of current yields

Treasury obligations, (ii) use of a wholly unrealistic market premium, (iii) his failure to use leveraged adjusted betas, and (iv) his failure to make a size adjustment.

Q: How has Dr. Woolridge approached the risk-fee rate of return component of the CAPM?

A: Both Dr. Woolridge and I have used the yield on Treasury obligations for the risk-free rate of return component of the CAPM. Unlike my approach, which included forecasts of these yields, Dr. Woolridge relied excessively on spot, one-day data in this regard. As indicated previously, the Blue Chip forecasts indicate higher yields on Treasury obligations for the future. The August 1, 2009 Blue Chip shows the yield on 30-year Treasury bonds increasing from 4.6% in the first quarter of 2010 to 5.0% in the fourth quarter of 2010. The June 1, 2009 issue of Blue Chip indicates that the yield on 30-year Treasury bonds will average 5.4% over the period 2011-2015.

Q: What are your observations regarding Dr. Woolridge's used of the geometric mean?

A: Dr. Woolridge has incorrectly considered the geometric mean when analyzing historical returns (see page 5 of Exhibit JRW-11). The theoretical foundation of the CAPM requires that the arithmetic mean must be used because it conforms to the single period specification of the model and it provides a representation of all probable outcomes and has a measurable variance. The geometric mean, which consists merely of a rate of return taken from two data points and cannot provide a reasonable representation of the market risk premium in the context of the CAPM. In short, the arithmetic mean provides an unbiased estimate, captures all probable outcomes, and has a measurable variance. I have covered this issue in additional detail above.

Q: Do you have additional observations concerning the CAPM as applied by Dr. Woolridge?

A: Yes. It appears to me that Dr. Woolridge has substantially misstated the total return for the market as a whole from which he calculates his market premium (i.e., Rm-Rf). The returns he provides, such as 7.45% (see his testimony at page 48), cannot possibly be correct. What Dr. Woolridge appears to show on his bar graph on page 7 of Exhibit JRW-11 is that the S&P 500 has a DCF return that is comprised of a 2.35% dividend yield and 5.1% (2.5% + 2.6%) growth rate. Such an assumption is totally unrealistic. To bring some perspective to the growth rate assumed by Dr. Woolridge, forecast growth rates are available for the Value Line Composite of 583 industrial, retail and transportation companies that includes 72 of Value Line's 98 industry groups and excludes financial services, utilities and non-North American companies. In its semi-annual forecast dated May 8, 2009, Value Line forecasts growth for the Industrial Composite of 6.5% for earnings per share, 7.0% for dividends per share, 6.0% for book value per share, and 14.5% for percent retained to common equity. An average of these four growth rates is 8.5% (6.5% + 7.0% + 6.0% + 14.5% = 34.0% ÷ 4). When combined with the 2.8% dividend yield published by Value Line, the return for the Value Line Composite is 11.30%, not 7.45% as Dr. Woolridge postulates. Moreover, the total return forecast by Value Line for the industrial composite is 22% as the midpoint of the range of returns of 17% as the low and 27% as the high.

Q: Are there other reasons to believe that the 7.45% market return determined by Dr. Woolridge is unrealistic?

A: Yes. A 7.45% overall return for the market is less than the DCF return that Dr. Woolridge calculates for his purportedly less risky gas group (see his testimony at page 24). It is simply inconceivable that the return on the stock market as a whole is only 7.45% if the return for his gas utility proxy group is 9.40%. It is apparent that his total market return is incorrect.

Q: Dr. Woolridge also questions the need to further adjust the CAPM results for size differences. Please comment.

A: Dr. Woolridge's arguments revolve around the purported distinction between regulated utilities and unregulated industrial companies. But, the Wong article employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because history shows that utilities generally have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns. Further, the article by Dr. Thomas Zepp presented research on water utilities that support a small firm effect in the utility industry.[4] Finally, Dr. Woolridge also interjects a citation (see page 94 of his direct testimony) to the 10th size decile in the Ibbotson study, even though I did not rely upon those data in developing my adjustment.

COMPARABLE EARNINGS

Q: Dr. Woolridge also quarrels with your Comparable Earnings approach. Please comment.

A: The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which

[4] Zepp, Thomas M. (2002) "Utility stocks and the size effect: revisited". Economics and Finance Quarterly, 43, 578-582.

new projects can be justified, and therefore undertaken. Because the Comparable Earnings method is derived from a firm's overall performance (i.e., its average return), the approach blends returns on a variety of projects that have produced returns above and below the cost of capital during the measurement period. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital. I have used this approach in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill established standards of a fair rate of return, i.e. namely, comparability and capital attraction. Counsel advises me that in the Hope decision, the United States Supreme Court defined these requirements as follows:

> ...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

The Comparable Earnings approach satisfies the Supreme Court's comparability standard. In addition, the financial community has expressed the view[5] that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets.

[5] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

PROPOSED RATE DESIGN CHANGE

Q: At pages 54-57 of his direct testimony, Dr. Woolridge discusses the relationship between rate design and the Company's risk and required return. Do you agree that the Company's rate design proposal warrants a reduction in its cost of equity?

A: No. As a preliminary matter, there are many items that affect earnings variability in addition to the variability of revenues. So while the Company's rate design proposal is intended to add stability to revenues, the Company continues to face variability in operating and capital costs that will contribute to earnings variability.

Q: Dr. Woolridge provides a tabulation on page 55 of his direct testimony as support for a potential downward adjustment of up to 50 basis points for the risk reducing effects of rate design. Is this adequate support for his adjustment?

A: No. While indicating that an adjustment of 50 basis points may be warranted for the Company's rate design proposal, Dr. Woolridge proposes to cut this in half and reduce his final recommendation by 25 basis points if the Commission adopts the Company's proposed rate design. But his proposal is far off the mark. In the recent NICOR Gas Company rate case order, the Illinois Commerce Commission only reduced the utility's equity return by 6.5 basis points for the 80% SFV rate design in that case. This shows that Dr. Woolridge has significantly overstated his downward adjustment.

Q: Ms. Brockway also argues that in the event that the Commission adopts the Company's rate design proposal, the reduction in risk should be reflected in the allowed return. Please comment.

A: The financial theories on which the cost of equity is based recognize that investors value their investments on a long-term basis covering a number of years, not just one year. Analyst forecasts of utility earnings growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather and other factors affecting usage, by definition are "normal" over the long-term but may vary year to year. Further, the DCF formula explicitly assumes a growth rate "approaching infinity."

Variations in usage due to weather and other factors represent company-specific risks that are irrelevant to the CAPM model, which focuses exclusively on "systematic" risks, i.e., the type of risks that an investor cannot mitigate through diversification of his or her investments. The risk implications of rate design are a firm-specific risk, and as such are an unsystematic risk, which is not measured by beta. Variations in usage and revenues constitute a company-specific risk, not an economic risk, and therefore SFV that mitigates that risk is a factor that does not determine the cost of equity.

This is not to say that there are no financial benefits from SFV, which do reduce the volatility in utility revenues. Indeed, I have controlled for this factor by assembling a group of proxy companies (i.e., the Gas Group), which at the time had decoupling features for each of the companies in the group. As such, my proposed cost of equity determination already reflects whatever risk attributes that there are associated with the Company's rate design proposal.

SUMMARY

Q: Please summarize your rebuttal testimony.

A: It is my opinion that the proposed rate of return on common equity recommended by Dr. Woolridge significantly understates the Company's cost of common equity. Further his proposals on capital structure, the cost of long-term debt, and the cost of short-term debt should be rejected. Further, based upon my cost of equity analysis that focuses on proxy group (i.e., Gas Group) companies that already have revenue stabilization mechanisms, there is no need to separately address the risk implications of the Company's rate design proposal that is contained in the testimony of Ms. Brockway, because it has already been priced into the market-based cost of equity set by investors.

Q: Does this conclude your Prepared Rebuttal Testimony?

A: Yes.

Columbia Exhibit No. _______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF MARK P. BALMERT ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

September 3, 2009

PREPARED REBUTTAL TESTIMONY OF MARK P. BALMERT

Q: Please state your name and business address.

A: Mark P. Balmert, 200 Civic Center Drive, Columbus, Ohio 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Robert J. Henkes filed Direct Testimony on behalf of the Attorney General related to Columbia's revenue requirement, Glenn Watkins filed Direct Testimony on behalf of the Attorney General related to Columbia's class-cost-of-service studies, Nancy Brockway filed Direct Testimony on behalf of AARP related to Columbia's proposed Gas Cost Uncollectible Charge, Jack E. Burch filed Direct Testimony on behalf of the CAC. This testimony will rebut the following issues: (1) the appropriate recording of proposed forfeited discount and miscellaneous revenue increases; (2) the appropriate class cost of service study as a basis of rate design; (3) the appropriate allocation of increased revenue requirement among the rate classes; (4) Columbia's incentive to manage the cost of uncollectible accounts under Columbia's proposed Gas Cost Uncollectible Charge; and, (5) the number of Columbia's customers at or below the poverty rate.

PROPOSED FORFEITED DISCOUNT AND MISCELLANEOUS REVENUE INCREASES.

Q: Do you agree with Mr. Henkes' recommendation on pages 15 of his direct testimony to add $535,828 to operating revenue?

A: I do not agree with the manner in which Mr. Henkes applies the $535,828 adjustment. Mr. Henkes' $538,828 adjustment to operating revenue shown on his attachment Sch. RJH-5 is the sum of three separate adjustments shown on his attachment Sch. RJH-6: (1) Weather Normalization Based on 25 years of weather data instead of 20 years of $197,963; (2) Incremental Forfeited Discount Revenues of $265,020; and, (3) Incremental Miscellaneous Service Revenues of $72,845. Columbia witness Efland is rebutting the Weather Normalization basis, and Columbia witness Cooper is rebutting the correct amount of Incremental Miscellaneous Service Revenues. It is how Mr. Henkes applies the adjustments that I disagree with. Below is a comparison of how Mr. Henkes applied the three adjustments to result in his Revenue Deficiency on his attachment RJH-1 and how the adjustments should have been used to determine Revenue Deficiency.

	Reference	Per Mr. Henkes Testimony	Proper Application of Adjustments	Corrected Difference
Columbia's Operating Revenue at current rates	RJH-6	$164,560,706	$164,560,706	$0
Weather Normalization 25-yr. (vs. 20 yr.)	RJH-6	197,963	197,963	0
Incremental Forfeited Discount Revenues	RJH-6	265,020	0	(265,020)
Incremental Miscellaneous Service Revenues	RJH-6	72,845	0	(72,845)
Operating Revenues Recommended by AG	RJH-6	$165,096,534	$164,758,669	($337,865)
Gas Supply Expense	RHJ-5	111,957,901	111,957,901	0
Other Operating Expense	RHJ-5	28,131,297	28,131,297	0
Depreciation Expense	RHJ-5	5,081,896	5,081,896	0

Taxes other than Income	RHJ-5	2,520,960	2,520,960	0
Income Taxes	RHJ-5	3,744,536	3,877,474	132,938
Operating Income	RHJ-5	$13,659,974	$13,455,047	($204,927)
Rate Base	RHJ-1	$166,493,215	$166,493,215	$0
Rate of Return	RHJ-1	7.23%	7.23%	
Operating Income Requirement	RHJ-1	$12,039,041	$12,039,041	0
Pro forma Operating Income	RHJ-1	$13,659,974	$13,455,047	(204,927)
Operating Income Deficiency	RHJ-1	(1,620,933)	(1,416,006)	(204,927)
Gross Revenue Conversion Factor	RHJ-1	1.657456	1.657456	0
Revenue Deficiency	**RHJ-1**	**(2,686,629)**	**(2,346,968)**	**339,661**
Rate Design:				
Revenue Deficiency		(2,686,629)	(2,346,968)	339,661
Less: Incremental Forfeited Discount Revenues	RJH-6	0	265,020	265,020
Less: Incremental Miscellaneous Service Revenues	RJH-6	0	72,845	72,845
Revenue Deficiency applied to base rates		(2,686,629)	(2,684,833)	(1,796)

As the above tale shows, Mr. Henkes adjusted operating revenue at current rates for the three revenue adjustments. This was a proper application of the first adjustment, the $197,964 for the difference in normalization methods. However, Mr. Henkes then adjusted operating revenue at current rates for his other two adjustments, Incremental Forfeited Discount Revenues of $265,020, and Incremental Miscellaneous Service Revenues of $72,845. These adjustments were made to reflect additional revenues expected to be collected as a result of proposed changes to Columbia's current tariff. Mr. Henkes includes these additional revenues in his revenue requirement as if Columbia was already recording these revenues on its books. By doing so, Mr. Henkes under calculated Columbia's revenue requirement by \$339,661 on his attachment Sch. RJH-1 as shown above. The \$339,661 represents the proposed additional revenue that Columbia has not yet received plus recovery for expected uncollectible accounts expense as a result of proposed billing incremental Forfeited Discounts and Incremental Miscellaneous Service charges and producing additional revenues. These additional revenues should then be subtracted from the total revenue requirement when designing proposed rates in the same manner as gas cost recovery, the proposed Gas Cost Uncollectible Charge, the Energy Assistance Rider and other miscellaneous revenues are subtracted in the determination of the revenue requirement to be recovered by the base rates to ensure no double recovery as shown above.

THE APPROPRIATE CLASS COST OF SERVICE STUDY AS A BASIS OF RATE DESIGN.

Q: Do you agree with Mr. Watkins that only one Class Cost of Service Study should be utilized in the determination of a fair and equitable distribution of the proposed revenue increase among the rate classes?

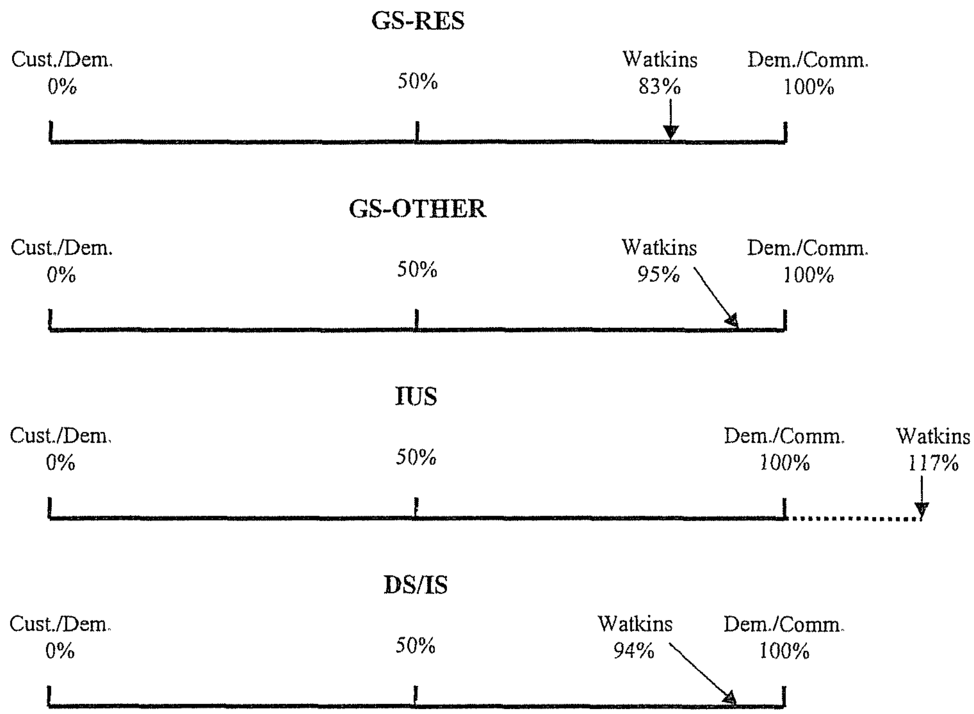
A: No I do not. Columbia believes that by providing both the demand-commodity and the customer-demand methodologies the two studies provide the outside limits of the possible allocations of mains to the various classes of service – i.e., the demand-commodity study produces results that are generally more favorable to the residential class while the customer-demand study produces results that are generally more favorable to the industrial class. Columbia recognizes that no one cost of service study is the "right" study, and the results of two such studies are useful in providing a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia has filed both a demand-commodity and a customer-demand study in each of its rate cases since the Commission's order on Columbia's 1988 rate case (Case No. 1988-10201) where the Commission stated on page 54, "The Commission is of the opinion that a well documented and carefully separated multiple-methodology approach to cost-of-service studies will provide it additional information for rate design. Therefore, Columbia is encouraged to submit cost-of-service studies of this sort in future rate proceedings".

Q: Do you agree with Mr. Watkins' statement on page 7 of his direct testimony that his single study is a "middle of the road approach"?

A: No I do not. First, while Mr. Watkins has agreed that my two class cost of service studies "likely provide two extreme ranges as to individual class rates of return" (see page 7, lines 13 and 14 of Mr. Watkins prepared testimony), he then goes on to compare the results of his study to the agreed upon range that Columbia's two class cost of service studies provide on page 17 of his prepared testimony based on Rate of Return on Rate Base. Below is Mr. Watkins' comparison.

Class	**Watkins**	**Balmert Customer/Demand (C/D)**	**Balmert Demand/Commodity (D/C)**
GS-RES	3.36%	1.11%	3.82%
GS-OTHER	7.84%	10.30%	7.71%
IUS	-1.36%	6.32%	2.78%
DS-ML/SC	--	--	--
DS/IS	5.57%	32.47%	3.55%
Total Company	5.17%	5.17%	5.17%

The diagram below shows the percentage within the established range that Mr. Watkins' study would produce for each of the rate classes. Where at 0% Mr. Watkins' study would match Columbia's customer - demand study and at 100% represent Mr. Watkins' study would match Columbia's demand - commodity study:



To me, a "middle of the road" approach implies a result somewhere around the middle – or about half way -- between the extremes of the range. If Mr. Watkins study was "middle of the road" the percentages above (difference of Mr. Watkins study and the Customer Demand study divided by the range created by the difference of the Customer / Demand and Demand / Commodity studies) would be much closer to the 50% level. Clearly Mr. Watkins' study produces nearly identical results as the Demand / Commodity study which Mr. Watkins himself has agreed produces an extreme end of the range of possible rate of returns for the rate classes. It is not surprising that Mr. Watkins' study produces results so close to the demand / commodity study which is known to favor the residential class.

Q: Mr. Balmert, do you agree with Mr. Watkins' statement on page 7 of his direct testimony that his single study "better reflects cost causation and is fair and equitable to all customer classes"?

A: No I do not. Like my Demand/Commodity study, Mr. Watkins' Peak and Average method allocates distribution Mains and related Mains costs based equal weighting of design day demand and throughput (average demand). The difference in the studies pertains to the design day demand in which Mr. Watkins excludes interruptible load. The purpose of my Demand/Commodity study is to set the opposite end of the range of returns based on use of the distribution system as opposed to a strict cost causation basis that my Customer/Demand study represents. Distribution systems are built to satisfy design day peak demand and not average demand and therefore average daily throughput is not a factor in the causation of the cost of the distribution system, rather it represents the average use of the system and gives weight to the balance of fairness that the allocation of cost should be in part based on use of the system so that all classes who benefit from the design of the system share in the cost of the system. However, Mr. Watkins' Peak and Average method totally ignores that the cost of distribution Mains is caused by both the diameter of the pipe (demand related cost), the length of the pipe (customer related cost) the age of pipe, and geography. By ignoring the customer related cost causation in his cost of service study, Mr. Watkins has not been fair and equitable to all classes of customers.

Q: Mr. Balmert, do you agree with Mr. Watkins' statement on page 8 of his direct testimony where he states, "there is no reasonable planning, design, or operational reason to allocate any portion of COK's Mains as customer related; i.e., allocated on customer counts"?

A: No I do not. As I have stated above, the cost causation of Mains is made up of the length of pipe, the age of pipe, the diameter of the pipe and geography. Based on a 2" minimum system study of the Mains Account (Attachment MPB-2 of my Prepared Direct Testimony) 61% of the Mains Account investment is considered customer-related while the remaining 39% is demand-related. Columbia lays up to 100 feet of Mains per customer at Columbia's expense (see Columbia tariff Original Sheet No. 61, Section 10). The customer pays for the additional cost of any extension beyond 100 feet either through a line extension agreement or a Contribution in Aid of Construction. Columbia makes an investment of up to 100 feet of pipe per customer added to the distribution system, this is a direct link between number of customers and investment in the length of pipe, thus customer-related cost causation.

Q: With regard to Mr. Watkins testimony on page 9, lines 1 -5 do you agree with Mr. Watkins that differences in customer use and differences in demands placed on the system during peak usage periods should be considered in a cost-of-service study?

A: Absolutely. In both my Demand/Commodity and Customer/Demand studies I have considered customer use variances, what Mr. Watkins calls "small usage" and "large usage" in the determination of the rate classes. The residential class does not have a usage range large enough to warrant a "small" versus "large" residential class, thus one residential class. The GS-Other class is separated from the IS class as well as the GDS class is separated from the DS class based on annual usage of 25,000 Mcf , and the DS-ML/SC class is separated as a class with no Mains investment. With regard to demands placed on the system during peak usage periods, both the Demand/Commodity and Customer/Demand studies include design day usage for all customers, including interruptible volumes as a partial basis of allocating Mains costs.

Q: With regard to Mr. Watkins testimony on pages 9 and 10, do you agree that geography is a basis of customer-based costs and did you consider it in your Customer/Demand study?

A: Geography was not separately measured or considered in the determination of the customer-related costs of Mains determined in the Customer/Demand study. Although I agree with Mr. Watkins that geography is a key driver of cost (urban versus rural, mountains versus farm land, downtown streets versus rural county road) it is a causation that cannot be measured, or at least the data is not available in Columbia's records to be measured. Therefore, geography was not a basis of determining customer-based Mains allocated costs. Further, there is no inherent reason to set different rates for different geographic areas because many other variables such as distance from the city gate, age of facilities, and so forth will cause cost differences. Thus, basing rates on average costs for the class of service is appropriate.

Q: With regard to Mr. Watkins testimony on page 13, do you agree that your Demand/Commodity method is unreasonably biased against large volume interruptible

customers because your approach includes interruptible demands in assigning Mains cost responsibility?

A: No I do not. Firm demand used in the design day allocation factors in both my class cost of service studies are classified as firm to identify Columbia's estimated service obligation as being firm in nature, which is the basis for Columbia's determination of its need for firm capacity on its upstream interstate pipelines. Interruptible demand used in the design day allocation factors is derived from Columbia's estimate of its expected total demand less firm demand on a design peak day. Columbia's distribution system is designed to handle load at design day temperatures regardless if the load is firm or interruptible on the upstream pipeline as long as Columbia is not experiencing upstream interruptions with the exception of two customers that have oil backup for their boiler plants, and therefore, design day interruptible volumes should have an equal weight to design day firm volumes in the allocation of Columbia's Mains and Mains related costs. In essence, Columbia must provide adequate capacity to deliver gas to each customer based on that customer's own maximum requirements: its non–coincident peak on the gas distribution system.

Q: With regard to Mr. Watkins testimony on pages 14 and 15, do you agree that uncollectible accounts expense should be allocated on a revenue ratio in the same manner Mr. Watkins proposes?

A: I agree with Mr. Watkins approach of using the commodity gas cost revenue as a basis of allocating uncollectible expense related to gas cost recovery revenue. I am concerned about using base revenue as a basis of allocating uncollectible expense related to base revenue simply because of the amount of uncollectible accounts expense allocated to the DS-IS and DS-ML classes. It is rare that Columbia writes-off a DS-IS account and even rarer that it writes-off a DS-ML account, however it is possible. I had used the customer ratio for two reasons: 1) Account 904 uncollectible accounts expense is classified by FERC as a Customer Accounts Expense, and even Mr. Watkins allocates Customer Accounts Expenses on customer based allocation factors; and, 2) the resulting allocated expense amounts are closer to actual experience by rate class than the revenue ratio. I say this because Columbia's uncollectible accounts expense accrual rate used for the cost of service and shown on Schedule D-2.1, sheet 5, line 4 of 1.410552% does not include any expected write-offs of Gas Measurement Billing Accounts (large volume billing accounts). The percentage only includes customer account billings through Columbia's DIS (small volume) billing system. The reason I did not exclude the large volume rate classes from any allocated uncollectible accounts expense is that over time there are charge-offs for these accounts and therefore they should receive a portion of the overall expense.

Q: With regard to Mr. Watkins testimony on pages 15 and 16, do you agree that Accounts 375.6 and Accounts 876 should be allocated in the same manner as Account 385?

A: Yes I do. Columbia's two class cost of service studies as filed included an Excel cell reference error which caused an incorrect allocation of Account 375.6 and Account 876. In Columbia's response to Staff data request 2-050 Columbia provided corrected studies that reflect the allocation of Account 375.6 and Account 876 in the same manner as Account 385 as was originally intended.

Q: With regard to Mr. Watkins testimony on page 16, do you agree the allocation of Account 902 (Meter Reading expense) and Account 903 (Records and Collections expense) should be weighted as Mr. Watkins suggests toward the large industrial customers?

A: No I do not. Mr. Watkins claims that the GS-Res and GS-Other customers should be weighted by 12 (once a month) while IUS, DS-ML/SC, and DS/IS customers should be weighted by 365 (daily) resulting in an allocation of costs 30 times (365/12) greater for the IUS, DS-ML/SC, and DS/IS customers than the GS-Res and GS-Other customers. Mr. Watkins' allocation of Meter Reading Expense implies that IUS, DS-ML/SC, and DS/IS customers are physically read 365 days a year in the same manner as the GS-Res and GS-Other customers are read in most cases, once a month. This is not the case. Although most Large Industrial customers do have daily and real time metering, the meter readings are performed by a computer, and not on a manual basis as most of the GS-Res and GS-Other customers are read, and therefore it could be argued that meter reading for the IUS, DS-ML/SC, and DS/IS customers could be actually less than the GS-Res and GS-Other customers. In any case Mr. Watkins has not offered any cost information supporting his contention that the basis of meter reading cost is 30 times greater for the IUS, DS-ML/SC, and DS/IS rate classes than the GS-Res and GS-Other classes.

Mr. Watkins' allocation of Records and Collections expense implies that costs for IUS, DS-ML/SC, and DS/IS customers are 30 times more expensive than the costs for GS-Res and GS-Other customers To accept Mr. Watkins' weighted customer allocation of Account 903 Columbia would have to incur 30 time the expense to collect revenue from the IUS, DS-ML/SC, and DS/IS classes than the GS-Res and GS-Other rate classes and Mr.

Watkins has offered no analysis showing that to be so. As for the cost of records I do agree with Mr. Watkins that the transportation customers require additional record keeping that the sales customer do not in particular with balancing supply, however as an offset it is logical that the sales customers would have a higher percentage of billing adjustments because of manual meter reading as opposed to the transportation customers with computer read readings. It is because of the arguments I have stated above, I believe than an equal weighting of Account 902 (Meter Reading expense) and Account 903 (Records and Collections expense) is fair and equitable to all classes and therefore Mr. Watkins weighting of the customers should be rejected.

THE APPROPRIATE ALLOCATION OF INCREASED REVENUE REQUIREMENT AMONG THE RATE CLASSES.

Q: With regard to Mr. Watkins testimony on page 19, do you agree with Mr. Watkins' proposed distribution among the rate cases of the revenue requirement increase proposed in this case?

A: No I do not. Mr. Watkins suggests "gradualism constraints" of "no class receive more than 150% of the Company-wide percentage increase in base rate revenue and no class receiving less than 50% of the Company-wide percentage increase in base revenue" without offering any basis of the selected percentages and ignoring the effects the increases have on the resulting return on rate base of the GS-Other and DS-IS classes in excess of the requested return on rate base, and thereby decreasing the parity among the rate classes instead of increasing it as Mr. Watkins has stated as guide to his recommendation (page 19, line 4 of his testimony).

Q: Do you agree with "gradualism constraints" with regards to distribution of revenue requirement?

A: Yes I do. However I first look at the current returns of each rate class resulting from the two class cost of service studies and the revenue requirement it will take to achieve the proposed total Company returns for each of the rate classes based on the middle of the range produced by the two studies. It is only if the revenue increase exceeds 10% for the class that I then apply a gradualism constraint. To do otherwise is not fair and equitable to all the classes and is contrary to the goal of working toward parity in returns among the rate classes.

Q: Using Columbia's corrected two class cost-of-service studies created in response to PSC data request 2-050, what are the rates of returns on rate base for each rate class at current rates compared to Columbia's proposed rates and Mr. Watkins proposed revenue distribution under Columbia's demand commodity (see Attachment MPB-15 to this rebuttal testimony) and customer demand (see Attachment MPB-16 to this rebuttal testimony) studies?

A:

	GS-Res	GS-Other	IUS	DS-ML/SC	DS-IS	Total CKY
D/C - Current	3.82%	7.91%	1.58%	--	3.24%	5.17%
C/D – Current	1.11%	10.54%	4.58%	--	31.21%	5.17%
Avg – Current	**2.47%**	**9.2%**	**3.08%**	--	**17.2%**	**5.17%**
D/C – CKY proposed	10.31%	9.19%	5.19%	--	3.36%	9.00%
C/D – CKY proposed	6.01%	12.04%	9.46%	--	31.66%	9.00%
Avg – CKY proposed	**8.16%**	**10.6%**	**7.33%**	--	**17.51%**	**9.00%**
D/C – Watkins proposed	9.33%	9.70%	3.79%	--	5.47%	9.00%
C/D – Watkins proposed	5.27%	12.64%	7.56%	--	39.39%	9.00%
Avg – Watkins proposed	**7.30%**	**11.17%**	**5.68%**	--	**22.43%**	**9.00%**

In looking at the comparison of the returns at the midpoint of the range created by the two class cost of service studies Mr. Watkins proposed allocation of increased revenue requirement is not entirely different from Columbia's spread. However, it is clear from the comparison that Columbia's allocation brings the returns of the rate classes closer to parity and limits the revenue increase to 9.93% for any one rate class (see Attachment MPB-6, page 1, of M. P. Balmert Direct Prepared Testimony) in the interest of gradualism. Columbia's allocation also considers that some of the rate classes include special contract and right-of-way contract customers whose rates cannot be changed. Mr. Watkins analysis apparently does not consider this. This is important because even though the rate class may have a reasonable increase, when applied to only those rates that can be changed within the class the increase may be unreasonable (i.e., the DS/IS class includes large special contract customers with alternative fuels).

COLUMBIA'S INCENTIVE TO MANAGE THE COST OF UNCOLLECTIBLE ACCOUNTS UNDER COLUMBIA'S PROPOSED GAS COST UNCOLLECTIBLE RIDER

Q: Do you agree with Ms. Brockway's testimony on page 20 of her testimony, where, in reference to Columbia's proposed Gas Cost Uncollectible Charge, she states, "The more that cost recovery tracks actual cost incurrence, the weaker is the utility's incentive to manage that cost effectively. In the case of commodity-related uncollectible expenses, weakening the incentive to manage such costs could lead to a less effective collection(s) and associated customer relations effort"?

A: No, I do not. Columbia is requesting that the Gas Cost Uncollectible Rider be calculated by using the uncollectible accounts expense ratio that is established in this case to be applied to the revenue generated by billing Columbia's commodity cost of gas. Because the uncollectible accounts expense ratio is proposed to be fixed, to the extent Columbia would put forth less effort in the collection of uncollectible accounts with a Gas Cost Uncollectible Charge than it did during the test year without a Gas Cost Uncollectible Charge, Columbia would be at risk of under collecting its actual uncollectible expense. The only difference between the current practice of including the recovery of uncollectible expense related to the billing of the commodity cost of gas and the proposed recovery of uncollectible expense related to the billing of the commodity cost of gas through the Gas Cost Uncollectible Charge is that the recovery will be allowed to change in proportion to the commodity cost of gas as it changes up or down. The Expected Gas Cost commodity rates are market driven and consequently when billed, generate an uncollectible cost over which Columbia has little or no control. Columbia will continue to be at risk for changes in uncollectible expense as it relates to base revenue, demand related gas cost, and most importantly the percentage of revenue that becomes uncollectible. This will give Columbia the type of incentives that Ms Brockway is referring to including the incentive to control collection and shut-off activity to reduce the expense of uncollectible accounts.

Q: Do you agree with Mr. Watkins' suggestion that the Gas Cost Uncollectible Charge may be better reflected within the gas cost recovery mechanism?

A: I do. Including the charge as part of Columbia's Gas Cost Adjustment Clause in lieu of Columbia's proposed separate surcharge mechanism makes sense considering the direct cause and effect of the two charges.

DETERMINATION OF THE NUMBER OF COLUMBIA'S CUSTOMERS THAT ARE AT OR BELOW THE POVERTY RATE.

Q: On page 6 of Mr. Burch's testimony he calculates an estimate of the number of Columbia customers living in poverty. Do you agree with Mr. Burch's estimate?

A: I believe his estimate is greatly overstated. Mr. Burch has created a chart listing by county the number of customers Columbia serves along with the poverty rates according to U.S. Census Bureau estimates. Mr. Burch then applied the poverty rate to the number of Columbia customers by county to develop an estimated number of Columbia Gas customers in poverty in each county. Mr. Burch then concludes at the bottom of page 6 of his testimony, "This data effectively illustrates the number of low-income families who cannot meet their basic needs with current income with a total estimate of more than 19,000 Columbia Gas customers living below the Federal Poverty Level".

Mr. Burch estimates that 19,229 of Columbia's customers are living below the Federal Poverty level. However, only 3,020 Columbia low income customers have actually received energy assistance through Federal Assistance, Federal Emergency, Citizens Energy, welfare Emergency Assistance and Matching Funds / Winter Care programs during the test year. A comparison of Mr. Burch's estimated low-income customers with the actual number of customers receiving assistance by county is shown in Attachment MPB-14 attached to this rebuttal testimony, along with the difference. Mr. Burch's estimate is materially greater in every county Columbia serves. While I would concede that not all customers who are eligible for utility bill assistance apply for such assistance, the differences between Mr. Burch's estimate and Columbia's actual experience are striking. This caused me to closely examine Mr. Burch's assumptions used in his analysis to understand why his results were so much higher than my expectations based on Columbia's experience in this area.

Mr. Burch makes several implicit assumptions to derive from the data described above the number of low income customers he claims are served by Columbia, including:

1. Each low income person in a county constitutes a gas utility customer;
2. Low income customers are uniformly distributed throughout the county, thus, the overall county percentage is reasonably applicable to the specific Columbia service area;
3. All low income customers use natural gas as their heating fuel; and
4. All low income customers pay for their own utilities.

As I demonstrate below, none of these assumptions are correct. First, for the state of Kentucky, 17.3% of all people live in poverty while only 13.2% of all families live in poverty based on 2007 data from the American Community Survey of the U. S. Census Bureau. It would be far more appropriate to estimate the number of low income gas customers served by Columbia using families rather than the number of people since using people assumes that each person represents a household, while poverty is defined based on household size. Because Mr. Burch assumes that the percentage of low income people times the number of Columbia gas customers in each county represents low income gas customers, his analysis greatly overstates the number of low income customers.

Next, many low income households may live in more rural areas of a county where the saturation of gas service is much lower than for more populated areas of the county. Further, the saturation of natural gas service for households varies widely by county. For example, the following table shows the saturation of natural gas service for the three Kentucky counties served by Columbia that are reported individually in the American Community Survey, and the estimated number of gas customers in poverty compared to Mr. Burch's estimates.

Table 1

Estimated Natural Gas Customers Below Poverty

Description	County		
	Fayette	Madison	Pike
Percent Use Natural Gas Heating	51.3%	20.8%	11.4%
Percent Families Below Poverty Level	10.5%	16.3%	14.8%
Natural Gas Weighted Poverty Percentage	5.4%	3.4%	1.7%
Number of Columbia Gas Customers	63,682	525	575
Estimated Number of Gas Customers in Poverty	3,439	18	10
CAC Estimate	10,125	98	120
Difference	6,686	80	110
Percent Difference	194%	444%	1,100%

Source 2007 American Community Survey

As is apparent, the estimates developed by Mr. Burch are greatly overstated compared to the refined estimates I have developed. For Fayette County alone, this reduces the estimated number of Columbia gas customers below poverty level by almost 6,700. Based on Public Use Microdata Areas ("PUMA") in the same 2007 survey, we know that other counties have lower percentages of customers using natural gas for heating. For example, PUMA5 00900 which includes Knott, Owsley, Letcher, and Lee Counties along with four other counties not served by Columbia has a natural gas usage level of 15.6%. PUMA5 02200 has data for Boyd, Carter, Greenup, and Lawrence counties served by Columbia and one county-Elliot-not served by Columbia. The natural gas usage percentage for this area is 38.4%. For the entire state of Kentucky, only 42.1% of all households use natural gas for heating. (American Fact Finder 2007 is based on data from the American Community Survey) If we assume that there is an equal probability that customers below the poverty level use the same fuel distribution as indicated for the entire state of Kentucky, the portion of customers using gas service below the poverty level should be reduced by 42.1% for all of the other counties in which Columbia serves besides the three counties presented above. I would note that this assumption represents the most favorable assumption for estimating gas consumers with income below the poverty level because generally the saturation of natural gas for renters is lower than for home owners implying that the assumption that the saturation of natural gas users is the same by income level may not reflect actual data. In addition, if we adjust for the families living in poverty, as opposed to using individuals, that would further reduce the numbers.

Moreover, there is no indication that any recognition was given by Mr. Burch to the fact that not all households pay their own utility bills. For example, in the 2007 ACS, residents in group homes including school dormitories would be counted in both the housing units and in the poverty statistics. However, dormitory residents generally do not pay for their utilities, and may have little or no income, although in reality they may not be below the poverty level. In Kentucky, 12.1% of renter occupied dwellings pay no extra charge for utilities. In essence, Mr. Burch's conclusion related to low income customers substantially overstates the number of Columbia gas customers below the poverty level. Based on the above information, I conservatively estimate that the total number of customers served by Columbia that are in poverty are no greater than about 6,300 customers.

Q: Please show how you calculated your estimate of Columbia customers that are in poverty.

A: Please see the table below:

Line No.	Reference	Amount
1	Mr. Burch total Columbia customers estimated on page 10 of his direct testimony	19,229
2	Less: Mr. Burch estimated Fayette County customers	10,125
3	Less: Mr. Burch estimated Madison County customers	98
4	Less: Mr. Burch estimated Pike County customers	120
5	Mr. Burch estimate for counties other than Fayette, Madison, and Pike	8,886
6	No. of Columbia customers shown on page 10 of Mr. Burch's direct testimony	121,505
7	Less: No. of Columbia customers in Fayette County	63,682
8	Less: No. of Columbia customers in Madison County	525
9	Less: No. of Columbia customers in Pike County	575
10	No. of Columbia customers for counties other than Fayette, Madison, and Pike	56,723
11	Poverty Rate of people using Mr. Burch's numbers on page 10 of his direct testimony for counties other than Fayette, Madison, and Pike (line 5 / line 10)	15.7%
12	Poverty Rate of households in Fayette Cty from American Community Survey	10.5%
13	Poverty Rate of households in Madison Cty from American Community Survey	16.3%
14	Poverty Rate of households in Pike Cty from American Community Survey	14.8%
15	Subtotal Poverty Rate of households	41.6%
16	Poverty Rate of people in Fayette County per page 10 of Mr. Burch's testimony	15.9%
17	Poverty Rate of people in Madison County per page 10 of Mr. Burch's testimony	18.7%
18	Poverty Rate of people in Pike County per page 10 of Mr. Burch's testimony	20.8%
19	Subtotal Poverty Rate of people	55.4%
20	Poverty Rate of households for counties other than Fayette, Madison, and Pike (line 15 / line 19 * line 11)	11.8%

21	Percent of households in the state of Kentucky using natural gas for heating	42.1%
22	No. of Columbia customers for counties other than Fayette, Madison, and Pike	56,723
23	Estimated Number of Gas Customers in Poverty for counties other than Fayette, Madison, and Pike (line 20 * line 21 * line 22)	2,818
24	Estimated Number of Gas Customers in Poverty in Fayette County (page 19 of this rebuttal testimony)	3,439
25	Estimated Number of Gas Customers in Poverty in Madison County (page 19 of this rebuttal testimony)	18
26	Estimated Number of Gas Customers in Poverty in Pike County (page 19 of this rebuttal testimony)	10
27	Total Estimated Number of Columbia Customers in Poverty (line 23 + line 24 + line 25 + line 26)	6,285

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Attachment MPB-14

Columbia Gas of Kentucky, Inc.
Low Income Customers by County
For the 12 Months ending 12/31/08

County	CAC Estimated Customers In Poverty 1/	CKY Energy Assisted Customers 2/	CAC Estimation in Excess of Actual Energy Assisted Customers
Bath	0	0	0
Bourbon	454	109	345
Boyd	1,590	243	1,347
Bracken	20	3	17
Carter	0	0	0
Clark	871	163	708
Clay	5	2	3
Estill	395	158	237
Fayette	10,125	1,262	8,863
Floyd	271	63	208
Franklin	1,419	163	1,256
Greenup	1,010	168	842
Harrison	237	85	152
Jessamine	97	1	96
Johnson	6	1	5
Knott	59	15	44
Lawrence	234	76	158
Lee	0	0	0
Letcher	0	0	0
Lewis	22	1	21
Madison	98	5	93
Martin	280	50	230
Mason	476	161	315
Menifee	13	4	9
Montgomery	486	114	372
Morgan	0	0	0
Nicholas	5	1	4
Owsley	9	2	7
Pike	120	12	108
Robertson	2	0	2
Scott	456	68	388
Woodford	469	90	379
Total	19,229	3,020	16,209

1/ Per table on page 6 of Mr. Burch's direct prepared testimony.

2/ CKY customers receiving assistance from Federal Assistance, Federal Emergency, Citizen Energy, Welfare Emergency Assistance and Matching Funds / Winter Care.

WATKINS
CUSTOMER-DEMAND
HISTORIC PERIOD - ORIGINAL FILING

COLUMBIA GAS OF KENTUCKY, INC.
RATE OF RETURN BY RATE SCHEDULE - @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED 12/31/2008

MPB-15
C/D STUDY
PAGE 1
WITNESS: M. Balmert

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	GS-RES.	GS-OTHER	IUS	DS-ML/SC	DS/IS	NOT USED	NOT USED	NOT USED	NOT USED
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				$	$	$	$	$	$	$	$	$	$
1		TOTAL REVENUES		176,126,437	109,241,049	59,252,202	217,272	745,225	6,670,689	0	0	0	0
1		COST OF GAS		111,744,211	69,116,582	42,433,947	193,682	0	0	0	0	0	0
2		OPERATING & MAINTENANCE EXPENSE		30,401,364	23,204,002	6,255,451	8,662	20,901	912,348	0	0	0	0
3		DEPRECIATION & AMORTIZATION		7,954,139	6,145,189	1,485,240	2,422	4,914	316,374	0	0	0	0
4		FEDERAL INCOME TAX		5,940,983	1,796,500	2,298,409	2,775	229,244	1,614,055	0	0	0	0
5		KENTUCKY STATE INCOME TAX		1,118,182	341,110	432,364	519	42,895	301,294	0	0	0	0
6		TAXES OTHER THAN INCOME		2,616,591	1,945,259	552,695	814	1,401	116,422	0	0	0	0
7		TOTAL EXPENSES & TAXES		159,775,470	102,548,642	53,458,106	208,874	299,355	3,260,493	0	0	0	0
8		OPERATING INCOME		16,350,967	6,692,407	5,794,096	8,398	445,870	3,410,196	0	0	0	0
9		INTEREST EXPENSE		4,778,115	3,339,984	1,205,609	2,922	1,905	227,695	0	0	0	0
10		INCOME AVAILABLE FOR COMMON EQUITY		11,572,852	3,352,423	4,588,487	5,476	443,965	3,182,501	0	0	0	0
11		RATE BASE		181,677,385	126,995,589	45,840,660	111,109	72,430	8,657,594	0	0	0	0
12		RATE OF RETURN AUTHORIZED ON RATE BASE		**9.00%**	**5.27%**	**12.64%**	**7.56%**	**(1)**	**39.39%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
13		UNITIZED RETURN		1.00	0.59	1.40	0.84		4.38	0.00	0.00	0.00	0.00

WATKINS
DEMAND-COMMODITY
HISTORIC PERIOD - ORIGINAL FILING

COLUMBIA GAS OF KENTUCKY, INC.
RATE OF RETURN BY RATE SCHEDULE - @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED 12/31/2008

MPB-16
D/C STUDY
PAGE 1
WITNESS: M. Balmert

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	GS-RES. (E)	GS-OTHER (F)	IUS (G)	DS-ML/SC (H)	DS/IS (I)	NOT USED (J)	NOT USED (K)	NOT USED (L)	NOT USED (M)
				$	$	$	$	$	$	$	$	$	$
1		TOTAL REVENUES		176,126,437	109,241,049	59,252,202	217,272	745,225	6,670,689	0	0	0	0
1		COST OF GAS		111,744,211	69,116,582	42,433,947	193,682	0	0	0	0	0	0
2		OPERATING & MAINTENANCE EXPENSE		30,401,360	20,425,115	6,965,328	12,049	20,901	2,977,967	0	0	0	0
3		DEPRECIATION & AMORTIZATION		7,954,139	4,970,304	1,785,388	3,849	4,914	1,189,687	0	0	0	0
4		FEDERAL INCOME TAX		5,940,982	3,622,624	1,831,902	551	229,244	256,661	0	0	0	0
5		KENTUCKY STATE INCOME TAX		1,118,181	677,827	346,345	108	42,895	51,006	0	0	0	0
6		TAXES OTHER THAN INCOME		2,616,594	1,487,158	669,714	1,369	1,401	456,952	0	0	0	0
7		TOTAL EXPENSES & TAXES		159,775,468	100,299,610	54,032,624	211,608	299,355	4,932,273	0	0	0	0
8		OPERATING INCOME		16,350,970	8,941,439	5,219,578	5,664	445,870	1,738,416	0	0	0	0
9		INTEREST EXPENSE		4,778,115	2,521,719	1,414,646	3,935	1,905	835,910	0	0	0	0
10		INCOME AVAILABLE FOR COMMON EQUITY		11,572,855	6,419,720	3,804,932	1,729	443,965	902,506	0	0	0	0
11		RATE BASE		181,677,385	95,882,867	53,788,833	149,606	72,430	31,783,647	0	0	0	0
12		RATE OF RETURN AUTHORIZED ON RATE BASE		**9.00%**	**9.33%**	**9.70%**	**3.79%**	**(1)**	**5.47%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
13		UNITIZED RETURN		1.00	1.04	1.08	0.42		0.61	0.00	0.00	0.00	0.00

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF AMY L. EFLAND ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

September 3, 2009

PREPARED REBUTTAL TESTIMONY OF AMY L. EFLAND

Q: Please state your name and business address.

A: My name is Amy Efland and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Nancy Brockway filed Direct Testimony on behalf of AARP challenging Columbia's assertion that gas usage will continue to decrease. Ms. Brockway also asserted that Columbia should have flatter usage in the future. I am rebutting these assertions made by Ms. Brockway.

Robert J. Henkes filed testimony on behalf of the Attorney General in which he challenged Columbia's definition of normal weather used in the weather normalization for the test year volumes. I am also rebutting this testimony.

Q: Does Columbia believe there will be a reduction in use per customer in the future?

A: Yes

Q: Why does Columbia believe that natural gas usage per customer will continue to fall in the future?

A: There are a number of factors that will contribute to the continued decline in use per customer. As I noted in my direct testimony, limited end uses for natural gas, continued improved appliance efficiencies and improved building standards will all contribute to the downward trend in consumption per customer. Appliance choice could also become a significant factor. If customers choose electric water heaters, cooking ranges and heat pumps this too could lower future usage levels.

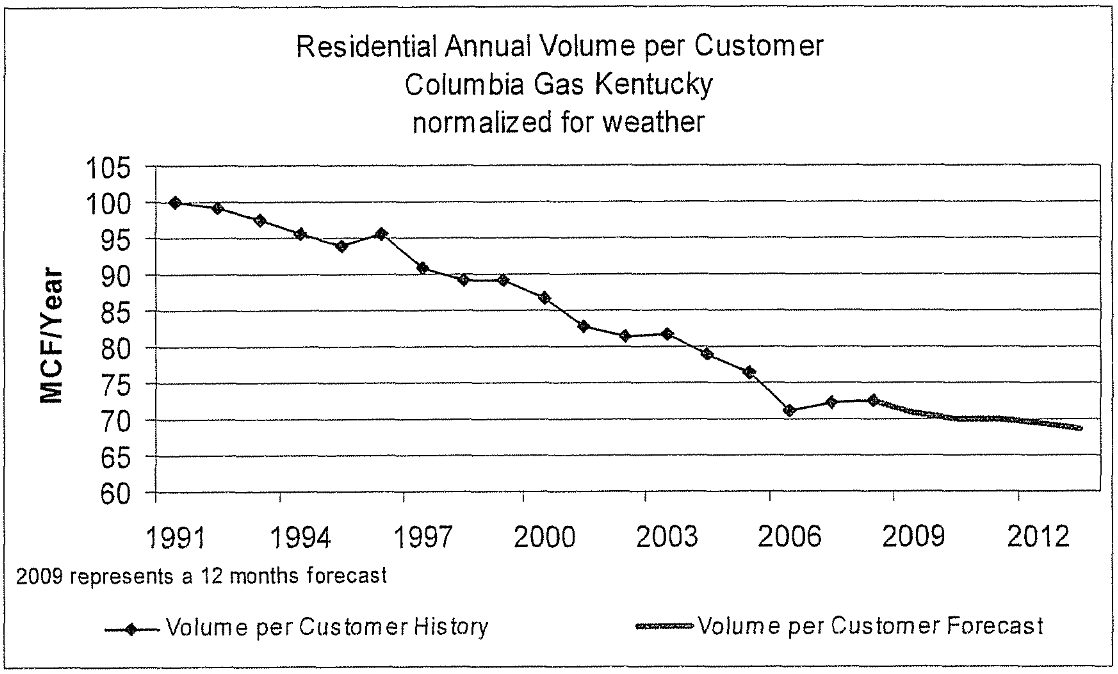
In addition, recent national policy initiatives may also lead to a reduction in use per customer. Kentucky has been recently awarded funds as part of the American Recovery and Reinvestment Act to support weatherization programs throughout the state. Federal tax credits are currently available for energy-efficient home improvements, which could also lead to reductions in natural gas use per customer.

Finally, Columbia has also proposed a demand side management ("DSM") program, the purpose of which is to decrease customer demand for natural gas. If approved, this program will also contribute to decreased natural gas use per customers. Columbia's proposed DSM program is addressed by Columbia witness Seelye.

Q: When considering these factors, does the forecast of residential gas use per customer assume same the rate of reduction that Columbia has historically experienced?

A: No. On page 13 of Ms. Brockway's testimony she points out that, "the Company provides no reason to expect that gas appliance efficiencies will improve at the same rapid rate as they did in the last ten years…" This is true, Columbia does not expect that gas appliance efficiencies will improve at the rate historically experienced. The forecast provided in my response to the AARP data request Set 1 No. 5, and reflected in the graph below, predicts a decline, but at a slower rate than historical levels. The graph includes both historic (1991-

2008) and forecasted (2009-2013) levels of use per customer. Over the period 1991 to 2008, the average annual change in use per customer is -1.9%. When considering the most recent ten years, 1999 to 2008, the average annual change is -2.0%. The forecast included in the graph, predicts the change in use per customer to be on average -1.0%. This rate is lower than the historic levels reflecting recent Columbia use per customer trends, and future limits in gas appliance efficiency improvements.



Q: What definition of normal weather did Columbia use in the preparation of this rate case?

A: As noted on page 4 of my Direct Prepared Testimony, Columbia defined normal weather as the average heating degree days for the twenty years ended 2008.

Q: Are Columbia's currently effective rates based upon billing determinants calculated by using a twenty-year definition of normal weather?

A: Yes, they are, as described in Columbia's response to PSC data request Set 2, number 58.

Q: Did the Attorney General's testimony continue to accept the twenty-year definition of normal weather?

A: No, Attorney General witness Henkes proposed the use of an average of the most recent 25 years of weather data. His stated concern is that Columbia's proposed twenty-year average is not consistent with NOAA's official published 30-year Heating Degree Day normal and that the 20-year normal may be overly volatile. In fact, Columbia agrees with Mr. Henkes' proposal to use an updated alternative to the traditional NOAA 30-year normal. NOAA acknowledges that the 30-year normal may not be appropriate for all customers and has developed an online tool on their website called "Dynamic Normals." This tools allows the user to calculate normals by selecting the start and end years.

In response to Mr. Henkes' concern that Columbia's proposed twenty-year average may be overly volatile, I have performed analysis comparing the 25-year normal to the 20-year normal. From this analysis, I have concluded that the 20-year average outperforms the 25-year average without exhibiting excessive year to year volatility

Q: Please describe your analysis.

A: An analysis of weather data shows that a rolling 20-year average is a superior measure to a rolling 25-year average. Table 1 below illustrates that when using the two averages to predict the years immediately following the last year of the averaging period, the 20-year average outperforms the 25-year average 69% of the time when considering the one-year ahead predictions from 1980 to 2008 and performs 68% better for the five-year ahead predictor. When considering the most recent ten years, 1999-2008, the 20-year average performs better than the 25-year average 70% of the time with respect to the one-year ahead predictor and 100% better than the 25-year average for the five-year ahead predictor. Table 2 demonstrates that stability is not sacrificed when using a 20-year normal. The average annual change for the 20-year average is 0.4%, while the 25-year average annual change is 0.3%. The 20-year measure is not only a better predictor, but also a more dynamic measure better able to react more quickly to change because it replaces 5% of the data each year rather than the 4% replaced with the 25-year average. In conclusion, the 20-year measure performs better compared to the 25-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 with the 25-year average.

Table 1

Weather Averages as Predictors

Moving Averages used to Predict Following Years

Columbia Gas of Kentucky

	Annual Heating Degree Days			Absolute Error		Better 1-year predictor		Better 5-year predictor	
	Actual	20-yr Average	25-yr Average	20-yr Average	25-yr Average	20-yr Average	25-yr Average	20-yr Average	25-yr Average
1980	5141	4810	4815	326	348	1			1
1981	4887	4815	4832	77	72		1	1	
1982	4453	4789	4828	362	379	1		1	
1983	4806	4780	4807	17	22	1		1	
1984	4601	4781	4807	179	206	1		1	
1985	4720	4783	4787	61	87	1		1	
1986	4381	4744	4770	402	406	1		1	
1987	4378	4733	4747	366	392	1		1	
1988	5007	4734	4747	274	260		1	1	
1989	4928	4732	4762	194	181		1	1	
1990	3828	4679	4727	904	934	1		1	
1991	4124	4663	4686	555	603	1		1	
1992	4415	4645	4679	248	271	1			1
1993	4738	4671	4669	93	59		1		1
1994	4476	4679	4649	195	193		1		1
1995	4815	4697	4646	136	166	1			1
1996	5050	4697	4670	353	404	1			1
1997	4896	4703	4675	199	226	1			1
1998	3934	4630	4664	769	741		1		1
1999	4203	4589	4659	427	461	1		1	
2000	4730	4569	4670	141	71		1	1	
2001	4258	4537	4638	311	412	1		1	
2002	4513	4540	4628	24	125	1		1	
2003	4672	4533	4599	132	44		1	1	
2004	4362	4521	4573	171	237	1		1	
2005	4485	4510	4546	36	88	1			
2006	4139	4498	4516	371	407	1			
2007	4271	4492	4509	227	245	1			
2008	4759	4480	4507	267	250		1		

	Mean Absolute Error		Frequency of Lowest Absolute Error			
1980-2008	270	286	20	9	17	8
1993-2008	241	258	10	6	6	6
1999-2008	211	234	7	3	6	0

	Relative Frequency of Lowest Absolute Error			
1980-2008	69%	31%	68%	32%
1993-2008	63%	38%	50%	50%
1999-2008	70%	30%	100%	0%

Table 2				
Stability of Weather Averages Annual Change in Averages 1980-2008 Absolute Values Columbia Gas of Kentucky				
	20-yr Average	25-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	0.3%	7.2%

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF PANPILAS W. FISCHER ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF PANPILAS W. FISCHER

Q: Please state your name and business address.

A: My name is Panpilas W. Fischer and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Robert J. Henkes filed Direct Testimony on behalf of the Attorney General related to income tax expense. This testimony will rebut the consolidated income tax adjustment recommended by Mr. Henkes.

Q: On page 42 of the testimony of Attorney General witness Henkes, he recommended the use of a consolidated tax adjustment in the calculation of income tax expense. Have you included a consolidated tax adjustment in your calculation of income tax expense?

A: No. In the calculation of income tax expense I have used a statutory federal income tax rate of 34% for taxable income up to $10 million per the Internal Revenue Code. This results in a reduction of income tax expense of up to $100,000 for taxable income up to $10 million versus using the statutory rate of 35% for all taxable income as proposed by Mr. Henkes.

Q: Why is a consolidated income tax adjustment not appropriate when Columbia Gas of Kentucky participates in the filing of a consolidated federal income tax return?

A: The tax losses in the consolidated return are generated by entities whose activities are not regulated by the Commission. Primarily, the tax losses are generated by NiSource Inc which represents an average of 83% of all the losses of the "chronic loss companies" used in Mr. Henkes' calculations. NiSource Inc's losses are the result of interest expense on the debt used to finance the goodwill (premium over book value paid) for which Columbia is not seeking recovery in rate base or in any manner in Columbia's rates. It would not be appropriate to use these non-regulated losses to subsidize Columbia's regulated utility operations, especially when the ratepayers are not being charged for any of the related costs.

Q: Are there any other problems with the consolidated income tax adjustment?

A: Yes. The use of a consolidated income tax adjustment results in an effective federal income tax rate that is not accurate or reliable. The effective federal income tax rate derived from Schedule RJH-15 prepared by Mr. Henkes ranges from 22.02% to 26.51% with an average of 24.05% over the five year period.

Q: What is the actual effective federal income tax rate of Columbia Gas of Kentucky?

A: Based on actual tax savings, the effective federal income tax rate ranges from 32.74% to 34.5% with an average of 33.75% over the five-year period. My calculations are included as Attachment PWF -1. That schedule demonstrates that the "effective tax rate methodology" used by Mr. Henkes produces a materially different result than the actual tax savings experienced by Columbia and is therefore not an accurate or reliable calculation.

Q: If Columbia were to include a consolidated income tax benefit adjustment in the calculation of income tax expense what amount should be used?

A: While the use of a consolidated income tax benefit adjustment in the calculation of income tax expense is not recommended for the reasons explained above, the actual tax savings, which averages $124,467 over the five year period, would be used along with a statutory federal income tax rate of 35% for all taxable income. As Mr. Henkes admitted in his testimony "CKY's ratepayers should only reimburse the Company for actual income taxes paid".

Q: Has the Commission taken a position on the issue of consolidated income tax benefits?

A: Based upon my review of prior Commission decisions, it appears that the Commission has not taken a single position on the issue of consolidated income tax benefits. In the Kentucky-American Water Company ("KAWC") rate case, Case No. 2004-00103, the Commission accepted the Attorney General's federal consolidated tax adjustment; however this was as a result of KAWC's previously touted filing of consolidated tax returns as a benefit to obtain the Commission's approval of its merger transaction. In the Louisville Gas and Electric Company ("LG&E)" rate case, Case No. 2003-00433, the Commission denied the use of an effective state income tax rate due to concerns that it is not known and measurable and that it is subject to fluctuations due to non-regulated tax losses or tax credits or apportionment adjustments from non-regulated activities. The Commission also expressed concerns that establishing the effective tax rate as a guideline or precedent could in the future result in higher utility rates to pay for taxes on non-regulated activities.

Since the Tax Reform Act of 1986 Columbia has recovered a 34% federal tax rate in its rate filing despite a 35% consolidated federal tax rate which came into effect when the Omnibus Budget Reconciliation Act of 1993 increased the federal tax rate to 35%. In Columbia's rate filings prior to 2001, there was no tax benefit related to the goodwill issue, and the Attorney General's office did not see fit to allow 35% recovery in rates by Columbia. Columbia's position in this case is consistent with its position in prior rate cases, whereas the Attorney General's position is one which apparently changes based on whatever position results in a lower recovery for the utility.

Q: What is your recommendation on the Attorney General's proposed consolidated income tax adjustment?

A: A consolidated income tax adjustment should not be used to calculate Columbia's income tax expense. A consolidated tax adjustment would be giving the ratepayers a benefit for expenses which Columbia is not seeking recovery. Also, the consolidated tax adjustment calculation proposed results in an unreliable and inaccurate result compared to any reduction in taxes actually paid by Columbia. Columbia shares the concern noted in prior Commission orders about using an effective tax. The Attorney General's proposed consolidated tax adjustment in the calculation of income tax expense should be rejected.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

COLUMBIA GAS OF KENTUCKY, INC.
Case No. 2009-00141

Attachment PWF-1

		2007	2006	2005	2004	2003
AG's Proposal:						
1.	CKY Taxable Income	5,363,129	26,574,636	12,201,552	11,464,455	2,836,171
2.	FIT @ 35%	1,877,095	9,301,123	4,270,543	4,012,559	992,660
3.	AG's Proposed Consolidated Income Tax Adjustment	(680,722)	(2,256,676)	(1,402,309)	(1,488,378)	(257,747)
4.	Total Tax Expense (Line 2+ Line 3)	1,196,373	7,044,446	2,868,235	2,524,181	734,913
5.	Effective Tax Rate (Line 4/Line 1)	22.31%	26.51%	23.51%	22.02%	25.91%
6.	Five Year Average ETR	24.05%				
Company's Calculation:						
1.	CKY Taxable Income	5,363,129	26,574,636	12,201,552	11,464,455	2,836,171
2.	FIT @ 35%	1,877,095	9,301,123	4,270,543	4,012,559	992,660
3.	Actual Tax Savings	(83,896)	(332,243)	(84,294)	(57,848)	(64,052)
4.	Total Tax Expense (Line 2+ Line 3)	1,793,199	8,968,880	4,186,249	3,954,711	928,608
5.	Effective Tax Rate (Line 4/Line 1)	33.44%	33.75%	34.31%	34.50%	32.74%
6.	Five Year Average ETR	33.75%				

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF JOHN J. SPANOS ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

September 3, 2009

PREPARED REBUTTAL TESTIMONY OF JOHN J. SPANOS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this testimony is to rebut the pre-filed direct testimony of Attorney General Witness, Mr. Michael J. Majoros, Jr. Mr. Majoros makes a number of recommendations regarding depreciation with which I disagree. The first subject of my rebuttal testimony is the use of the Equal Life Group ("ELG") procedure in calculating depreciation accrual rates for all asset classes for Columbia Gas of Kentucky, Inc. I will also address Mr. Majoros' testimony related to cost of removal.

Q. CAN YOU SUMMARIZE YOUR POSITION IN THIS PROCEEDING?

A. The depreciation accrual rates in this case were calculated using the ELG procedure because it is the most accurate procedure for matching capital recovery to utilization or consumption of the assets. Additionally, the accrual rates are calculated with a component of net salvage. The net salvage percent for each account is determined consistently with almost every other utility in the United States and Canada. It is known as the straight line accrual approach as the estimated net salvage costs are recovered equally over the life of the asset. Some view this as the traditional approach.

Q. WHAT ARE THE KEY POINTS ON DEPRECIATION WITH WHICH MR. MAJOROS DISAGREES?

A. There are two major issues related to depreciation. The first is the development of depreciation rates using the ELG procedure versus the Average Service Life ("ASL") procedure. The second issue relates to the net salvage component of the depreciation rate. Columbia's proposal utilizes the traditional straight line accrual approach while Mr. Majoros recommends the present value method. The traditional straight line approach is utilized by all utilities in Kentucky, as well as almost every utility across the United States and Canada.

Q. PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE.

A. In the ELG procedure, the property group or account is subdivided into groups of equal life based on the estimated survivor characteristics of the account. The depreciation for each equal life group is based on the straight line method, that is, an equal amount of the group's service value is recorded as depreciation in each year of service. The total depreciation for the account is the summation of the depreciation for each equal life group. For this reason, this procedure is also known as the unit summation procedure.

Q. CAN YOU SHOW IN A SIMPLE EXAMPLE HOW THE EQUAL LIFE GROUP PROCEDURE COMPARES TO THE AVERAGE SERVICE LIFE PROCEDURE?

A. I will use a two unit example to show how the ELG procedure more appropriately matches recovery to consumption. Each unit costs $1,000. Unit A will be in service for 5 years and Unit B will be in service for 15 years. There is no net salvage anticipated for these units.

If depreciation is determined using the ASL Procedure, then it would be determined that the average service life for the two units is 10 years ((5 + 15)/2) and the depreciation rate is 10% (1/10 years). Therefore, the total account original cost is $2,000 and the annual depreciation amount is $200 ($2,000 times 10%). At the end of year 5, the total annual accrual for the account is $1,000 (200 times 5). Also affecting the accumulated depreciation is the retirement of Unit A for $1,000. Thus, the accumulated depreciation for the account at the end of year 5 is zero ($1,000 annual accruals minus $1,000 retirements). At the beginning of year 6, we have $1,000 of original cost, an accumulated depreciation level of $0 and one unit that has one-third of its service life expired. With the ASL procedure, the 10% rate or $100 of annual expense is booked for years 6 through 15 and at the end of year 15 we retire Unit B. We collected $1,000 in annual accruals during years 6 through 15 and made a retirement of $1,000 at year 15, so our original cost and accumulated depreciation are both zero, so full recovery was achieved. However, if we focus on the end of year 5, we had one unit remaining with two-thirds of its life expectancy still to be consumed, but 100% of the investment to be recovered. This method did not match recovery to consumption in the most appropriate manner.

In contrast, if depreciation is determined using the ELG procedure, then the depreciation expense would be recorded quite differently. I will use the same two unit example to illustrate the ELG calculation. Unit A will be in service for 5 years, therefore it will have a 20% (100 divided by 5 years) rate. Unit B will be in service for 15 years, and will have a 6.67% (100 divided by 15 years) rate. Consequently, depreciation expense for years 1 through 5 would be $200 ($1,000 times 20%) for Unit A and $66.67 ($1,000 times 6.67%) for Unit B. At the end of year 5, the total annual accruals would be approximately $1,334 ($1,000 for Unit A and $334 for Unit B). Unit A would be retired at the end of year 5, so the accumulated depreciation at the end of year 5 is $334 ($1,334 of annual accruals minus $1,000 retirement). In years 6 through 15, the annual accruals would be $66.67 for a total to $666 for the 10-year period. Thus, at the end of year 15, the accumulated depreciation is $0 ($1,000 of accruals minus the $1,000 retirement of Unit B), so full recovery was once again achieved. However, if we look back at the end of year 5, we can see recovery of Unit A matched consumption of Unit A at the time the unit went out of service, and more importantly Unit B has survived one-third of its expected life and recovery was one-third ($334/$1,000) of the expected recovery. A much more appropriate recovery pattern is recorded using the ELG procedure.

This two unit example is used to understand the recovery patterns of the two procedures; however, there are many historical transactions that affect the rate of each of these procedures that complicates the depreciation rate for each account. The following table sets forth the activity for the accumulated depreciation using the two methodologies.

COMPARISON OF ACCUMULATED DEPRECIATION
AND ANNUAL ACCRUALS USING THE
ASL VS ELG PROCEDURES

		ASL			ELG		
Year	Plant Balance	Annual* Accruals	Retirements	Accum. Depr. Balance	Annual** Accruals	Retirements	Accum. Depr. Balance
1	2,000	200	0	200	267	0	267
2	2,000	200	0	400	267	0	534
3	2,000	200	0	600	266	0	800
4	2,000	200	0	800	267	0	1,067
5	2,000	200	1,000	0	267	1,000	334
6	1,000	100	0	100	66	0	400
7	1,000	100	0	200	67	0	467
8	1,000	100	0	300	67	0	534
9	1,000	100	0	400	66	0	600
10	1,000	100	0	500	67	0	667
11	1,000	100	0	600	67	0	734
12	1,000	100	0	700	66	0	800
13	1,000	100	0	800	67	0	867
14	1,000	100	0	900	67	0	934
15	1,000	100	1,000	0	66	1,000	0

* Annual Accruals = Plant Balance Multiplied by Rate (10%)
** Annual Accruals = Plant Balance Multiplied by Rate for Each Unit

Q. IF THE ELG PROCEDURE IS SUPERIOR TO THE ASL PROCEDURE IN MATCHING DEPRECIATION EXPENSE WITH THE CONSUMPTION OF SERVICE VALUE OF THE ASSETS, WHY WAS THE ASL METHOD ONCE COMMONLY USED IN DEPRECIATION STUDIES?

A. Although the ELG or unit summation procedure has been known to experts for many years (it was described by Robley Winfrey as the only mathematically correct procedure in 1942), its widespread use was constrained by the large amount of computations required. However, the ASL procedure could readily be performed without the aid of computers and became the choice of experts by default. With the advent of modern computer equipment, this constraint has been removed. Therefore, the ELG procedure which was unquestionably more accurate is now available to all companies.

Q. DOES THE ELG PROCEDURE RELY ON THE ESTIMATED SURVIVOR CURVE MORE THAN THE ASL PROCEDURE WHEN THE REMAINING LIFE BASIS IS USED?

A. No, it does not. Both the ELG and ASL Procedures use the forecasted survivor curve to weight the remaining lives within each vintage of plant. The ELG procedure uses a reciprocal weighting of the remaining lives and the ASL procedure uses a direct weighting.

Q. IS IT NECESSARY TO RECALCULATE ELG DEPRECIATION RATES EVERY YEAR?

A. No. Regardless of the method used, depreciation rates must be periodically reviewed, but it is not necessary that they be reviewed every year with the ELG method. Over a period of a few years, the annual depreciation rates of relatively mature property do not vary sufficiently to necessitate annual recalculations. Further, to the extent that minor changes would have been required, the use of the remaining life basis corrects for such over- or under-accruals when revised rates are determined.

Q. ON PAGE 13 OF HIS TESTIMONY, MR. MAJOROS DISCUSSES RETROACTIVE VERSUS GOING FORWARD IMPLEMENTATION OF THE ELG PROCEDURE. SHOULD YOUR STUDY BE CHARACTERIZED AS RETROACTIVE IMPLEMENTATION?

A. No, it should not. The use of the ELG procedure does not change past recovery amounts. In either my study or Mr. Majoros' ASL presentation, the same amount of future accruals and a remaining life basis for determining the annual depreciation expense in this proceeding, are used. Since the amount of future accruals related to this topic is the same whether the ELG or ASL procedures are used for embedded plant, as reflected in the fact that the future accruals are the same, there can be no retroactive implementation. The future accruals are determined by subtracting the actual book reserve from the original cost, so past recovery is not a variable based on depreciation procedure.

The issue in this proceeding is the grouping of the future accruals. The future accruals can be segregated into groups of equal life or can remain as a single amount at this property group level. The use of the ELG procedure will permit the recovery of future accruals related to each item over its actual remaining life rather than the use of averages with the future accruals for the entire account.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE USE OF THE ELG PROCEDURE OF UTILITY PLANT FOR COLUMBIA GAS OF KENTUCKY, INC.?

A. The ELG procedure provides a better match of depreciation expense with the consumption of an asset's service value. The ELG procedure improves the matching of expense and consumption of service value and should be adopted in this proceeding in the manner that I have proposed.

NET SALVAGE FOR ACCOUNTS

Q. CAN YOU DISCUSS THE ISSUE RELATED TO NET SALVAGE OR SPECIFICALLY COST OF REMOVAL?

A. Yes, I can. Mr. Majoros' proposes a drastic change from the traditionally accepted method of this Commission as well as the accepted method of almost all other Commissions and regulatory bodies. The emphasis of the change is to apply financial reporting rules to regulatory recovery instead of using the previously established sound rate-making practices. These recommendations of Mr. Majoros have been continually rejected for this improper application as well as the fact that it causes unnecessary burden on future customers in order to benefit today's ratepayers. Mr. Majoros' methods back-load recovery and are intended only to lower depreciation.

Q. WHAT ARE NET SALVAGE AND NEGATIVE NET SALVAGE?

A. Net salvage is the gross salvage value of retired property less the cost of removal of such property. If cost of removal exceeds salvage value, the net salvage is negative, hence, negative net salvage.

Q. WHAT IS MR. MAJOROS' PROPOSAL FOR NET SALVAGE?

A. He has proposed a radical change in the basis for determining allowance for net salvage for all accounts for Columbia. His proposal is that net salvage should be discounted to a present value level for determining the calculation of depreciation.

Q. HAS MR. MAJOROS CONSISTENTLY MADE THIS PROPOSAL FOR CHANGING NET SALVAGE PERCENTS FROM THOSE PROPOSED BY MR. SPANOS?

A. No, he has not. Mr. Majoros continually makes different proposals to adjust net salvage percents, seemingly with the single motive of reducing depreciation expense not just proper recovery. As can be seen in past cases in Kentucky alone, he switches from the cash basis proposal to the present value proposal to a normalization proposal. An example of Mr. Majoros' change in net salvage proposals would be Case No. 2005-0042, for Union Light, Heat and Power Company. None of these proposals are designed to accomplish the definition of depreciation which is recovery of the full service value of the assets during the life of the asset in a rational manner, which is the basis of my traditional proposal. Depreciation is not intended to be a result oriented calculation, yet Mr. Majoros continually changes his approaches. I assume he does this in order to achieve the result of reducing depreciation.

Q. DO AUTHORITATIVE TEXTS ON DEPRECIATION SUPPORT YOUR PROPOSAL RELATED TO NET SALVAGE?

A. All authoritative texts on the subject of depreciation support my proposal to accrue for net salvage in the traditional manner presented in my study. The two depreciation texts most often cited by depreciation experts as authoritative support the traditional approach that I have proposed. *Public Utility Depreciation Practices*, published in 1996 by the National Association of Regulatory Utility Commissioners states:

> Closely associated with this reasoning are the accounting principles that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also

> requires that the estimated cost of removal of plant be recovered over its life.[1]

Depreciation Systems, another widely accepted text states the concept in this manner:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.[2]

Q. WHAT TREATMENT OF NET SALVAGE DO YOU PROPOSE?

A. I propose, consistent with the authoritative texts and the policy of the very large majority of regulatory commissions, the traditional incorporation of net salvage in the determination of depreciation. The traditional approach has been used by this Commission in establishing Columbia's ratemaking allowances for depreciation for decades. The traditional approach collects net salvage costs ratably over the life of plant from the customers served by the plant. This approach is equitable and conforms to the definition of depreciation as the loss in service value, where service value is the difference between original cost and net salvage.

Q. YOU STATED THAT IT IS MORE APPROPRIATE AND EQUITABLE TO RECOGNIZE NET SALVAGE COSTS DURING THE LIFE OF THE RELATED PLANT. PLEASE EXPLAIN.

A. The net salvage cost of an item of plant is a part of its service value and, therefore, it is a part of the item's cost of providing service. The cost of the item providing service should be collected from the customers that receive the service. Thus, an allocable por-

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1 Public Utility Depreciation Practices. Page 157. National Association of Regulatory Utility Commissioners. 1996.

2 Depreciation Systems, Wolf, Frank K. and W. Chester Fitch. Page 7. Iowa State University Press. 1994.

tion of the net salvage cost should be recovered each year from the customers receiving the value of the service rendered by the item of plant in the same way that an allocable portion of the item's original cost is recovered from such customers each year. This approach is equitable in that customers are responsible for the costs of plant that provide service to them. This is a sound ratemaking principle. This concept does not include the notion of also discounting to present value the future recovery because the results are too high.

Q. PLEASE ILLUSTRATE THIS PRINCIPLE AS IT APPLIES TO NET SALVAGE COSTS WITH A SIMPLE EXAMPLE.

A. Consider a single customer, Customer A, served by a gas service line that does not provide service to other customers. The original cost of the service line is $5,000 and it is installed when the customer is added to the system. The estimated life of the service line is 40 years and the estimated net salvage is negative 60 percent. The annual depreciation expense to be recovered from this customer using the straight line whole life accrual of net salvage is $200 per year ($5,000 x 1.60 / 40 years). The annual depreciation expense to be recovered from this customer using Mr. Majoros' present value approach of net salvage is $141 per year ($5,000 x 1.13 / 40 years). (The 12.7% is extracted from Exhibit MJM-4, page 1 of 6 for Account 380.)

In year 25, the customer moves out and another customer, Customer B, moves into the residence served by this service line. During the 25 years, a total of $5,000 ($200 x 25 years) was collected from the Customer A under the straight line whole life accrual of net salvage. Only $3,525 ($141 x 25 years) would be collected under the present value method.

At the end of year 40, the service line is replaced at a total cost of $8,000, $3,000 to remove the old service line and $5,000 to install the new service line. (I have excluded inflation from the example to promote a better understanding of the principle.) Under the straight line whole life accrual method, the depreciation expense in year 40 would continue at $200 ($5,000 x 1.60 / 40 years). Under the present value method, the sum of the depreciation collected would be $5,640 ($141 x 40 years), however, the total cost would have been $8,000. Thus, the present value approach recovers a portion of the service value of the asset, but did not accomplish full recovery of the total service value. Therefore, using the remaining life technique, Customer B would actually pay the difference in rates between the $5,640 of accruals and the $8,000 of actual expenditures. This is not equitable between customers.

This example is obviously simplified and excludes inflation, but it does not change the fact that Mr. Majoros's approach will not give full recovery of the service value of each asset. In this example, it is undeniable that $8,000 is the cost to the utility for this service line, which should be recovered in depreciation expense. Unlike Mr. Majoros's approach, the traditional approach, which I recommend and which is used exclusively by almost all regulatory bodies, provides full recovery of the service value of the asset.

Q. WHAT WERE THE STATISTICAL BASES FOR YOUR NET SALVAGE ESTIMATES?

A. The statistical bases for my estimates of net salvage were the historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or the required costs to remove.

Q. DOES THE USE OF THESE STATISTICAL BASES RESULT IN THE COLLECTION OF FUTURE INFLATED REMOVAL COSTS FROM CURRENT CUSTOMERS?

A. Yes, to a certain extent. The reliance on historical indications of net salvage as a percent of the original cost retired will result in the collection of net salvage costs at a future price level. However, such reliance also assumes that there will be substantial improvements in technology, comparable or lesser environmental regulations and a significant reduction in inflation.

Q. DOES THE USE OF NET SALVAGE PERCENTS THAT ARE COMPARABLE TO THE HISTORICAL INDICATIONS ASSUME THESE EVENTS?

A. Yes. The net salvage percents, which are the net salvage costs divided by the original costs of the assets that have been retired and expressed as percents, are related to the retirement of plant that on average is significantly younger than the average service life of the plant in service, on an original cost dollar weighted basis. For example, the average age of retirements of gas services during the most recent 30 years, 1979-2008, is approximately 20 years. This is considerably less than the average life of 39 years estimated for this account.

The average net salvage percent related to these retirements, made on average at age 20, was negative 60 percent. That is, after 20 years in service, the plant was retired and the cost to remove the plant, as a result of inflation, technological changes and other factors, was 60 percent of the cost to install the same plant.

The future retirements of the total current gas services in service will have an average age that actually exceeds the average life. Thus, future retirements will be of plant that has been in service nearly two times as long as the plant retired during the period 1979-2008. For retirements at such ages to experience net salvage that is 60 percent of the cost to install, there will have to be a reduction in the rate of inflation adjusted for technological improvements. If the rate of inflation adjusted for technological improvements that occurred between the installation and retirement of plant retired during the period 1979-2008 occurred over a period that is nearly two times as long, the net salvage cost would be much greater as a percent of the original cost of the plant retired.

Q. WHAT IS THE IMPLICATION OF THE ASSUMPTION THAT THE FUTURE RATE OF INFLATION ADJUSTED FOR TECHNOLOGICAL IMPROVEMENTS WILL BE LESS THAN THE HISTORICAL RATE?

A. The implication of this assumption as reflected in my estimates of net salvage percents is that the resultant net salvage accruals are most likely inadequate to recover the total net salvage costs over the entire life cycle of the plant currently in service.

Q. DO YOU HAVE ANY CONCERN THAT THE LEVEL OF NET SALVAGE COSTS INCURRED WILL BE LESS THAN THE AMOUNTS THAT YOU HAVE ESTIMATED?

A. No, I do not. Net salvage costs will be incurred. The estimates that I have made will almost certainly result in the recovery of less, not more, net salvage than the actual costs incurred.

Q. IS IT APPROPRIATE TO ASK CURRENT CUSTOMERS TO PAY FOR FUTURE COSTS OF REMOVAL AT A PRICE LEVEL THAT IS GREATER THAN TODAY'S PRICE LEVEL?

A. Yes, it is. The future cost to remove an item of plant is part of the service value that it renders to current customers and a ratable portion of such costs should be recovered from these customers. That is the theory of depreciation, i.e., the loss in service value during a specific period. As these future costs are recovered from current customers, they are deducted from rate base. This deduction in the amount on which the utility is entitled to earn a fair return, in effect, represents an amount on which the customer earns a return or otherwise stated the utility reduces its requirement for return. That is, as customers provide for the future cost of removal, they receive a return on such amounts because less rate base is required. This is fair compensation for making payment prior to the cost incurrence by the utility. Further, as already noted, by charging customers for these costs during the life of the plant; the customers that benefit from the plant, or consume its service value, are the ones who pay for such service. Customers paying today for future costs of removal and receiving a return on such payments is no different than the utility recovering today amounts that it invested many years ago, but on which it earned a return until the amount was recovered from customers.

Q. WHY ARE THE CURRENT NET SALVAGE ACCRUALS SO MUCH GREATER THAN THE CURRENT EXPERIENCE?

A. The difference in price level as described above is part of the difference. Another significant difference is that the current experience is related to plant retirements that largely come from an older plant base that was constructed to serve fewer customers, whereas the current net salvage accruals relate to the plant presently in service that serves a much larger customer base.

Q. IS IT APPROPRIATE FOR COLUMBIA TO COLLECT AMOUNTS FOR FUTURE NET SALVAGE COSTS THAT ARE GREATER THAN THE AMOUNTS CURRENTLY EXPENDED FOR SUCH COSTS?

A. Yes, it is. Although the amount that my study proposes to collect from customers for future net salvage costs is greater than the amount currently expended for such costs, the amount that Columbia spends for plant additions is far greater than the amount that it proposes for the recovery of original cost. If net salvage accruals should be limited to discounted net salvage expenditures, then full recovery will not be achieved during the life of an asset. Thus, the amount for recovery of costs is far less than actual expenditures. Equity considerations require that customers pay for the service value, original cost less net salvage, of the plant from which they receive service. The fact that this results in accruals for net salvage that are greater than the current experience is not inappropriate.

Q. HAS MR. MAJOROS EXPANDED ON HIS DISCUSSION OF COST OF REMOVAL IN THIS CASE AS COMPARED TO THE PREVIOUS CASES BEFORE THE COMMISSION?

A. Yes, he has. In this case, he proposes to move previously accrued cost of removal from accumulated depreciation to a regulatory liability. He states the reason for this is because the amounts are not specifically recognized as regulatory liabilities for ratemaking purposes. However, he does not mention that Columbia continually records the incurred cost of removal and gross salvage into the accumulated depreciation account. He also does not mention that the purpose of remaining life accrual rates insures full recovery of the service value of all assets which includes the cost of removal at end of life.

Q. WITH THE REMAINING LIFE METHOD IN PLACE, IS THERE A REASON TO MAKE THIS CHANGE?

A. No, there is not. There are different regulatory and financial rules and practices that should be maintained for their intended purposes. The Statement of Financial Accounting Standard No. 143 is a financial reporting pronouncement, not a regulatory rate-making practice, thus, it should not be applied to future depreciation practices.

Q WHAT IS YOUR RECOMMENDATION RELATED TO NET SALVAGE.

A. The portion of the annual depreciation accrual rates and amounts proposed by Columbia in this proceeding that is related to net salvage is reasonable and in accordance with sound ratemaking principles. Depreciation is the loss in service value and service value is the difference between original cost and net salvage value. Thus, net salvage should be a part of the straight line whole life depreciation accrual.

Net salvage costs should be recovered from customers served by the plant that results in the expenditure of net salvage costs. The use of a straight line whole life accrual over the life of the asset accomplishes this equity. The present value net salvage approach does not. It is appropriate for the net salvage accrual to exceed the current net salvage cost during a period of system growth and prior to reaching a steady state for the plant.

The estimates of net salvage percents used in developing the net salvage accrual are very reasonable and likely understate the future net salvage costs that will occur. Almost every state, including Kentucky, uses the traditional approach of straight line whole life or remaining life accrual of net salvage during the life of the asset, as I have recommended. Considerations of customer equity with regard to the matching of depreciation expense with the consumption of service value should control. The proposal to discount net salvage costs should be rejected and the traditional approach of accruing for such costs during the life of the related asset should be retained. Finally, the accrued cost of removal should be maintained in accumulated depreciation, not moved to a regulatory liability for ratemaking purposes.

Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes, it does.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF JUNE M. KONOLD ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF JUNE M. KONOLD

Q: Please state your name and business address.

A: My name is June M. Konold and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Robert J. Henkes filed Direct Testimony on behalf of the Attorney General related to Columbia's request for separate rate treatment for its Pension and Other Post-Retirement Employee Benefits ("OPEB") expenses. This testimony will rebut Mr. Henkes' testimony that Columbia's Pension and OPEB expenses are not volatile, do not have a significant financial impact on Columbia, and do not justify the creation of the Rider POM mechanism. I will also be rebutting the Direct Testimony of Michael J. Majoros, Jr. that was also filed on behalf of the Attorney General and will refute his assertion that Mr. Spanos' approach to calculating depreciation for the cost of removal is precluded by GAAP and that International Financial Reporting Standards ("IFRS") does not provide for the recognition of regulatory liabilities. I will also discuss the relevance of Mr. Majoros' discussion of the Georgia Power filing to this case.

Q. How will your testimony be structured?

A. My testimony is structured to address the testimony of Mr. Henkes first and the testimony of Mr. Majoros second.

Rebuttal to testimony of Mr. Henkes

Q. Does the percentage of Pension and OPEB O&M expenses compared to Columbia's total O&M expenses provided on pages 50 and 51 of Mr. Henkes' testimony, provide a clear picture of the magnitude and volatility of these costs to Columbia?

A. No, it does not.

Q. Please explain why not.

A. The O&M expenses that Mr. Henkes presented on pages 50 and 51 of his testimony primarily consist of gas supply expenses which severely distort the percentages that Mr. Henkes provided.

Q. Could you please provide the percentage of Pension and OPEB O&M expense as a percentage of O&M exclusive of gas supply expenses?

A. Yes. The table below provides these percentages and provides a more accurate representation of the impact of Columbia's Pension and OPEB expense.

	Pension & OPEB Expense (1)	Total O&M Expense	% of Pension & OPEB Expense
2004	$ 920,452	$ 26,691,730	3.45%
2005	$ 871,132	$ 28,191,102	3.09%
2006	$ 606,730	$ 26,395,803	2.30%
2007	$ 537,585	$ 24,053,971	2.23%
2008	$ 377,127	$ 28,271,959	1.33%
2009 (Est)	$ 1,772,186	$ 30,619,000	5.79%

(1) Application of CKY for Accounting Order, Case No. 00168, paragraph j on page 3.

Q. Are Pension and OPEB costs volatile?

A. Yes. As described in my Direct Prepared Testimony, Columbia's Pension and OPEB expense has varied significantly during the last six years as illustrated in the following table[1].

Year	Pension Expense	Change From Prior Year	Percent of Change	OPEB Expense	Change From Prior Year	Percent of Change
2004	$ 289,648			$ 630,804		
2005	$ 212,790	$ (76,858)	26.5%	$ 658,342	$ 27,538	4.4%
2006	$ (104,133)	$ (316,923)	148.9%	$ 710,863	$ 52,521	8.0%
2007	$ (4,727)	$ 99,406	95.5%	$ 542,312	$ (168,551)	23.7%
2008	$ (152,146)	$ (147,419)	3118.7%	$ 529,273	$ (13,039)	2.4%
2009 (Est)	$ 980,525	$ 1,132,671	744.5%	$ 791,661	$ 262,388	49.6%

The volatility of these expenses creates a situation where it is almost impossible for Columbia or the Commission to determine a representative level of Pension and OPEB expense for inclusion in base rates. Rider POM allows the Commission and Columbia the ability to set rates on an annual basis to recover Pension and OPEB expense in a timely manner without having to incur the significant expense of filing a base rate proceeding. Rider POM is a long-term solution to this problem that not only alleviates the difficulty of trying to determine a representative level of Pension and OPEB expense to include in base rates, but also ensures that Columbia's customers pay no more or no less than the prudently incurred costs associated with its Pension and OPEB obligations.

Q. Did Mr. Henkes accept Columbia's proposed pension and OPEB expenses of $1,772,186 for purposes of setting the base rates in this proceeding?

A. Yes, he did. On page 52 of his testimony, Mr. Henkes specifically states "I have accepted the Company's proposed pension expenses of $980,525 and $791,661 in this case."

[1] Table reflects pension and OPEB amounts attributable to O&M expense only.

Q. If the Commission should deny Columbia's request for Rider POM, what is Columbia's proposal for the treatment of Pension and OPEB expenses?

A. As indicated by Columbia in its request for an Accounting Order in Case No. 2009-00168, the 2009 estimated Pension and OPEB O&M expenses are $1,208,103 over that which is reflected in Columbia's current base rates as illustrated below:

	2009 Estimated Expense	Current Base Rate Recovery	Difference
Pensions - Retirement Income Plan	$ 980,525	$ (15,800)	$ 996,325
OPEB - Retiree Medical & Group Life Insurance	$ 509,963	$ 298,188	$ 211,775
OPEB - Amortization of Transition Obligation	$ 281,698	$ 281,695	$ 3
Total	$ 1,772,186	$ 564,083	$ 1,208,103

This results in a significant deterioration of Columbia's 2009 earnings due to conditions entirely beyond its control. In the event that the Commission might agree with Mr. Henkes' recommendation to accept Columbia's proposed Pension and OPEB expense of $1,772,186 in this case, Columbia proposes that the Commission: (1) allow for the deferral of the difference between the Pension and OPEB O&M expenses incurred as of January 1, 2009 and the Pension and OPEB O&M expense reflected in Columbia's base rates; and, (2) provide for the subsequent recovery of this deferral, including carrying costs, in a future rate proceeding.

<u>Rebuttal to Testimony of Mr. Majoros</u>

Q. On page 17 of Mr. Majoros' testimony, he implies that Mr. Spanos' approach to calculate depreciation for the cost of removal is not GAAP and that his approach is specifically precluded by GAAP. Do you agree with this assertion?

A. No, I do not.

Q. Please explain.

A. Within Appendix B67 of SFAS No 143, Accounting for Asset Retirement Obligations, the Financial Accounting Standards Board ("FASB" or "Board") acknowledged that the way in which asset retirement obligations costs are treated for financial reporting purposes and the way in which they are treated for rate-making purposes often differ. The Board concluded in B68 that because the practices of regulators for allowing costs related to asset retirement activities are well established, the Board did not consider any future changes in those practices. The Board also noted in B73 that many rate-regulated entities currently provide for the costs related to asset retirement that are not within the scope of SFAS No. 143 and that the objective of including those amounts in rates currently charged to customers is to allocate costs to customers over the lives of those assets.

As Columbia witness Mr. Spanos has noted in his Prepared Rebuttal Testimony, authoritative texts on the subject of depreciation support his proposal to accrue for net salvage in the manner presented in his study and that this approach is followed by a large majority of regulatory commissions, including this Commission.

Q. On page 21 of Mr. Majoros' testimony he states,

> **"The Company will argue that the Commission should not rely on SFAS No. 143 or FIN 47 for purposes of deciding ratemaking issues. For purposes of deciding what approach is most consistent with principles of accrual accounting, however, I believe there is no better source than SFAS 143 and the other FASB pronouncements that are, after all, the embodiment of GAAP."**

Do agree with that comment?

A. I disagree with the first part of that comment. I disagree that Columbia is arguing that the Commission should not rely on SFAS No. 143 or FIN 47 for purposes of deciding ratemaking issues. In fact, I believe that SFAS No. 143 supports Columbia's position. As previously noted, the FASB acknowledged that the way in which costs are treated for financial reporting purposes and the way in which they are treated for ratemaking purposes often differ. B68 of SFAS 143 states that, "Because the practices of those regulators for allowing costs related to asset retirement activities are well established, the Board did not consider any future changes in those practices." As Columbia witness Mr. Spanos points out, his approach is followed by a large majority of regulatory commissions, including this Commission.

Q. For financial reporting purposes, does Columbia account for liabilities related to asset retirement obligations pursuant to GAAP?

A. Yes, it does. Columbia reports asset retirement obligations for financial reporting purposes related to those obligations that are within the scope of SFAS 143 and regulatory liabilities for asset retirement obligations that are outside the scope of SFAS 143.

Q. Mr. Majoros stated that he has concerns regarding International Financial Reporting Standards ("IFRS") and indicated that IFRS does not provide for regulatory liabilities. In his testimony he states, "In my opinion, what GAAP has brought – i.e., identification of the SFAS No. 143 Regulatory Liability – IFRS will take away by transferring it to equity." Do you share his concern regarding the loss of regulatory liabilities?

A. No, I do not. In fact, in July 2009, the International Accounting Standards Board ("IASB") issued an Exposure Draft for Rate-Regulated Activities that specifically provides for the recognition of regulatory assets and regulatory liabilities. Even in the absence of the Exposure Draft for Rate-Regulated Activities, International Accounting Standard ("IAS") 37, "Provisions, Contingent Liabilities and Contingent Assets" specifically provides for the recognition of legal and constructive obligations. IAS 37 defines a constructive obligation as "an obligation that derives from an entity's actions where:

a) by an established pattern of past practice, published policies or sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and

b) as a result, the entity has created a valid expectation on the part of those other parties that it will discharge those responsibilities."

Columbia's asset retirement obligations that fall within the scope of SFAS 143 and those that fall outside the scope of SFAS 143 would meet the definition of legal and constructive obligations under International Accounting Standards and would therefore be recognized as such.

Q. Mr. Majoros discusses the filing by Georgia Power and asserts that it intends to take the over-collections for cost of removal into its own income. Do you recommend that the Commission place much importance upon the Georgia Power filing?

A No, I do not. Columbia has never proposed to amortize "over-collections for cost of removal into its own income" nor does it intend to do so. Furthermore, Columbia has never stated that it agrees with the position taken by Georgia Power.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF
ERICH A. EVANS
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF ERICH A. EVANS

Q: Please state your name and business address.

A: My name is Erich A. Evans and my business address is 200 Civic Center Dr., Columbus, OH 43215.

Q: Did you file Direct Prepared Testimony in this proceeding?

A: Yes, I did.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: Subsequent to the filing of my Prepared Direct Testimony, Scott White filed Direct Testimony on behalf of Interstate Gas Supply, Inc. and Glenn A Watkins, filed Direct Testimony on behalf of the Attorney General related to the proposed Price Protection Service ("PPS") and the proposed Negotiated Sales Service ("NSS"). This testimony will rebut the following PPS and NSS issues raised in other parties' testimony: (1) PPS and NSS would be harmful to competition: (2) Columbia would have an unfair advantage over marketers: (3) Columbia's base rates will subsidize the PPS and NSS programs: (4) the GCA will be harmed by PPS and NSS; and, (5) that NYMEX futures entered into for PPS and NSS could impact the GCA.

Q. Do you agree with both Interstate Gas Supply, Inc ("IGS") and the Attorney General's opinion that PPS and NSS will hurt competition?

A. No, and in fact it could help competition based upon evidence from existing PPS and NSS programs in other utilities. On page 43 of his testimony, Mr. Watkins states that he believes

PPS and NSS would "stifle competition," but he does not provide any evidence to support this. Throughout Mr. White's testimony, he states that PPS and NSS will compete with his company and states why he thinks it will be unfair competition, but provides no actual evidence. In fact, it is my belief that the addition of PPS and NSS will spur competition, through the addition of additional choices for consumers in an environment which has, to some extent, suffered from a lack interest and participation by gas marketing companies. Furthermore, the evidence from the existing PPS and NSS programs at other utilities proves that these programs are not harmful to competition. These programs have been in effect for many years, and competition has expanded where they do exist. On utility systems where those programs have been approved and implemented, marketers have been able to operate and have not been hindered by the PPS and NSS programs even as the utilities actively market PPS and NSS and consistently have customers in those programs.

Columbia's proposed PPS and NSS programs simply would permit Columbia to offer an alternative rate to its sales customers. These new rate offerings will, in some instances, compete with offerings from marketers. That has the effect of increasing competition – the more competitors there are in a market, the more competitive that market is.

Q. Are you familiar with the PPS and NSS programs offered by utilities in any other states?

A. Yes, I am familiar with the PPS and NSS programs offered by Columbia Gas of Pennsylvania ("CPA) and Northern Indiana Public Service Company ("NIPSCO") in Indiana.

Q. Based upon your familiarity with the Pennsylvania and Indiana programs, what have you observed about the effects of these programs upon competition?

A. Columbia Gas of Pennsylvania ("CPA") has had a NSS program since the late 1990's. That NSS rate is available to commercial and industrial customers and those same customers also have the option of receiving their gas from a marketer. Marketers currently serve over 80% of the usage of customers that are eligible for transportation. The marketers have been competing with NSS for over 10 years and they have over 80% of the market. That alone shows that a NSS program is not harmful to competition.

NIPSCO is another utility that has had a NSS program for over 10 years. Like CPA, NIPSCO's NSS program is available to the same customers who are also eligible to receive gas from marketers. At NIPSCO the marketers have not been harmed by the NSS program and have consistently served over 80% of the eligible market.

The same can be said for the PPS programs. CPA has recently started a PPS program. CPA started marketing and advertising for PPS in March of this year. That implementation has not harmed competition. In fact, the number of customers enrolled in Choice increased 7% from March to June of this year. If PPS were harmful to competition then marketers would not have been able to have experienced a 7% growth rate over a five-month period when advertising for PPS was taking place.

NIPSCO has a PPS program that the Indiana consumer advocate requested the company implement when its Choice program was started. As at CPA, Choice participation has grown at NIPSCO since PPS started. The PPS program includes a customer education component, helping customers become more knowledgeable and willing to sign up for not only PPS, but for Choice as well. While both Choice and PPS started at the same time at

NIPSCO, this additional education has been a benefit to the marketers. The Choice program has grown from being equal in size to PPS to now being double the size of the PPS program. At the bottom of page 3 of his testimony, Mr. Whites statements seem to predict these results that we have experienced at other utilities when he states that, "IGS welcomes competition and in fact encourages other suppliers to enter into the service territory because IGS believes that robust competition benefits consumers and competitors alike."

Given all of the above it is my conclusion that PPS is not harmful to competition, but on the contrary, promotes improved customer education, interest and participation in both programs

Q. Will Columbia be at an unfair advantage over the marketers with PPS and NSS?

A. No, the PPS and NSS programs are different than what marketers offer. On page 4 of his testimony, Mr. White states that these programs will be "largely unregulated." Mr. White is choosing to ignore that these programs are being proposed as regulated tariff services. Columbia will file both PPS and NSS prices and contracts with the Commission. The gas cost is tied to the GCA though the Weighted Average Cost of Gas ("WACOG"), and the Commission has oversight of the GCA. Columbia is just asking to keep the risk of loss separate from the GCA and the customers. This does not put the programs at an unfair advantage over the marketers. Even though PPS and NSS are offered by the utility the marketers still have many advantages over the programs. Based on the experience of other utilities, the PPS and NSS programs appeal to customers who like the idea of a negotiated rate, but want a basic service from the utility. The marketers do not have to file their prices or contracts with the Commission and therefore are able to offer much more sophisticated products and their services appeal to a larger number of customers.

Q. How can marketers offer more sophisticated products than those offered by Columbia?

A. The marketers are not limited to prices defined in a tariff. For example, PPS will offer a fixed price or an index price. However marketers can offer combinations of those prices. They are able to offer a contract where the price is fixed for a set number of months and then it becomes an index rate. They are also able to offer an index rate with a cap, so it never goes above a set amount. The proposed PPS and NSS tariffs require twelve-month contracts. Marketers are not limited to a set contract length. They can offer different contract lengths and terms where PPS and NSS contracts are filed with the Commission.

Marketers are free to design many different prices and terms. That flexibility gives them a big advantage over the utility offering PPS and NSS.

Q. Is it a problem if the call centers are handling PPS, NSS, and other calls?

A. No. When marketers are advertising for their services they do not list Columbia's phone number. So a customer phoning Columbia is calling because they have a question about their Columbia bill or they are calling about services Columbia offers. On page 6 of Mr. White's testimony he states that customers call Columbia with "questions about suppliers" and "offers". While he is trying to imply that Columbia discusses these topics with customers, it is simply not true. Columbia does not talk about marketers or any of their offers. If a customer calls in asking about a specific marketer the customer is referred to that marketer.

If they call in asking about Choice, they are provided a list of the marketers supplying Choice customers. This would be no different when Columbia is offering PPS and NSS. In fact the call center will not be handling the NSS calls.

Q. For other utilities with a PPS program, what has been their experience with the call centers?

A. One of the requirements on the PPS program in CPA is that the call center must be separate. This has caused customers to become upset and confused. Customers are calling Columbia when they want to deal with Columbia. Today in CPA, customers have called in to ask about a bill question and get some information about PPS. What happens is that they have to be transferred around to different groups. The group that handles PPS is separate from the group that can talk about their bill. This is leading to customers being very upset and not understanding why the Commission required the separation. NIPSCO's PPS program does not have this requirement. That is much better for the customers, and as previously discussed it is not causing harm to the Choice program.

Q. Do you agree with IGS' contention that PPS and NSS should be separated from all of Columbia's other functions?

A. No, the proposed PPS and NSS rate are sales service rates being offered by the utility. As such they do not need to be fully separated from Columbia's other functions. They are optional services and as such some of the costs should be borne by just those customers who choose these rates. That is why Columbia will recover the cost to create the programs as well as advertising, marketing, and program administration costs in the rates charged to just those customers on PPS and NSS.

Q. Do you agree with IGS' contention that Columbia will have unfair access to Columbia's systems, purchasing decisions, and its hedging program?

A. No. Columbia does have access to its own systems, but this does not cause any unfair conflict. Again looking at the utilities that currently offer PPS and NSS programs, having access to the systems has not given them an unfair advantage. The marketers at NIPSCO and CPA serve a larger number of customers than are enrolled in the respective PPS and NSS programs. Having PPS and NSS in the same systems with the other sales customers has not caused any harm to the marketers.

Mr. White, on pages 7 and 8 of his testimony, also makes reference to the purchasing decisions of Columbia. This would not give Columbia any advantage. As proposed, PPS and NSS will credit the GCA at the monthly average gas cost. Since it is the average cost of all gas purchased that month, it is impacted by all purchases; meaning any spot or mid month purchases made will affect this average. Columbia is at risk in its WACOG price determination due to a number of factors that marketers do not need to contend with. Columbia must, without fail, balance the needs of transportation customers, CHOICE customers and its GCA customers every day of the year. If any of the customers, including the marketers' Choice and transportation customers, use more or less gas than forecasted, and they always do as a result of changes in weather, factory production levels or any number of reasons, or if supplies delivered on behalf of transportation and Choice customers by their marketers is greater than or less than expected, then it falls upon Columbia to see to it that the proper supplies are available to ensure reliability. This responsibility places price risk on the PPS and NSS programs, even though it may not be those customers that are causing the supply actions taken by Columbia. It is impossible to know in advance when and to what extent these changes are going to happen. As a result, the WACOG approach to pricing does not provide Columbia an advantage, but rather places more price risk on Columbia.

In Mr. White's testimony, on pages 4 and 11, he also references the existing hedging program at Columbia and states that this will provide an unfair advantage to Columbia. The hedging program he refers to is for the system supply and is done with financial hedges. Columbia is not buying physical gas for its GCA hedging program. Therefore, the GCA hedging program will not have any impact on the WACOG cost of gas proposed for the PPS and NSS programs. The WACOG will only contain the cost of physical gas flowing for that month excluding any gas going into or out of storage. Therefore, the hedging program that Columbia manages for the GCA will only impact the GCA, and will have no impact on the cost of gas for the PPS and NSS programs.

Q. Will the proposed rate increase help fund PPS and NSS?

A. Mr. White, on page 5 lines 13 – 15 of his testimony, states that Columbia is recovering the cost to offer PPS and NSS from all customers. This is not true. No costs for PPS and NSS are included in the rate case. On pages 6 and 7 of his testimony, Mr. White goes into more detail about costs that Choice marketers face with the implication that Columbia will not face the same costs in offering PPS and NSS. Again Mr. White is incorrect in his statements. Columbia has stated that the uncollectible costs for PPS and NSS will not be included in its uncollectible rider; Columbia will be at risk for those costs. This is a greater risk than the marketers take. Under Choice the marketers know what their uncollectible costs will be since it is set by the amount that Columbia pays the marketers for their receivables.

Q. Will PPS and NSS avoid start up costs that marketers face?

A. In Mr. White's testimony, on page 13, he states that Columbia will be able to avoid "any of the startup or on-going costs borne by competitive suppliers." Mr. White has not provided any details of what IGS' start up costs have been. However, Columbia will still have start up costs and on-going costs that will never be recovered except through the PPS and NSS rates. This is the same way marketers recover their costs. Columbia is not seeking recovery for the cost of administering the PPS and NSS programs. While Columbia will use existing personnel, [they are corporate services employees who do not allocate their time and expenses to Columbia Gas of Kentucky. Likewise the cost of advertising will not be recovered.

Q. Are separate natural gas purchases needed?

A. No, Columbia had two gas supply options for the PPS and NSS programs. The supply could be streamed to the programs where Columbia would make separate purchases for PPS and NSS, or Columbia could use a common pool of supply for all customers. With the streamed supply option, a question could be raised whether Columbia is simply taking the lowest price gas for PPS and NSS. With a common pool of supply, this argument is eliminated. This is why Columbia chose the common pool of supply option; it also has the benefit of not impacting the GCA. On pages 8 – 11 of Mr. White's testimony he discusses the proposed methodology for PPS and NSS. However his logic appears to be flawed. Mr. White seems to be under the impression that Columbia will be making separate purchases for PPS and NSS and just adding those purchases into the common pool of supply. In fact for supply purchases, Columbia will consider the supply needs of the PPS and NSS customers with all of the other sales customers. No separate purchases will be made for these programs. The GCA will receive a credit from the PPS and NSS program based on the WACOG price multiplied by the specific volumes purchased each month by the PPS and NSS customers. This prevents any subsidy of the programs.

Q. IGS' contests the use of NYMEX futures to hedge PPS and NSS price risk since usage can not be predicted perfectly, and he appears to believe that the program will result in GCA customers being impacted by that risk. Is he correct in that understanding?

A. No, GCA customers will not be at risk to imbalances between PPS / NSS hedges and PPS / NSS supplies purchased. Mr. White is correct when he states that the hedged volume will never exactly match up with the purchases by PPS and NSS customers, and there will always be some amount over hedged or under hedged. However, the argument made on page 9 of Mr. White's testimony that this hedge mismatch will impact the GCA is wrong. The hedges entered into for PPS and NSS will be transacted in a separate account from the GCA hedges and will never be part of or impact the GCA price. Therefore any over or under hedge will only impact Columbia and not the customers or the GCA.

Q. Do you agree with IGS's contention that there is no volume reconciliation between the GCA and PPS/ NSS?

A. Again Mr. White's is incorrect. On page 8 of his testimony he states "[t]here is no volume reconciliation". He is choosing to ignore an important part of the design of the PPS and NSS programs. Columbia has proposed that PPS and NSS will in fact have an annual true up to the GCA. This will ensure that the GCA is properly credited for all volumes used by PPS and NSS customers.

Q: Does this complete your Prepared Rebuttal Testimony?

A: Yes, it does.

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of adjustment of rates of Columbia Gas of Kentucky, Inc.	))	Case No. 2009-00141

PREPARED REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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September 3, 2009

PREPARED REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD

Q: Please state your name and business address.

A: My name is Russell A. Feingold and my business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

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

A. I am employed by Black & Veatch Corporation as a Vice President and I lead the Rate & Regulatory Advisory Group of its Enterprise Management Solutions ("EMS") Division.

Q. Please describe the firm of Black & Veatch Corporation.

A. Black & Veatch Corporation has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. EMS is the management consulting division of Black & Veatch. EMS delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, EMS delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University - St. Louis in 1973 and a Master of Science Degree in Financial Management from Polytechnic University - New York in 1977.

Q. What has been the nature of your work in the utility consulting field?

A. I have over thirty-four (34) years of experience in the utility industry, the last thirty-one (31) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A to my testimony.

Q: Mr. Feingold, have you previously testified before any regulatory authorities?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies. In addition to traditional utility costing and rate design concepts and issues, my testimony has addressed revenue decoupling concepts and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Ratemaking ("PBR") concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States. Finally, I have been accepted as an expert witness in each of the above-described regulatory jurisdictions where I have participated in judicial proceedings.

Q: On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Columbia Gas of Kentucky, Inc. ("Columbia" or the "Company").

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: The purpose of my rebuttal testimony is to respond to the testimony of AARP and the Kentucky Office of Attorney General ("OAG") related to the Company's proposal to implement a Straight Fixed-Variable ("SFV") rate design for its General Service - Residential Rate Schedule. I will specifically respond to the claims made in the direct testimonies of AARP witness Nancy Brockway and OAG witness Glenn A. Watkins related to the impact of Columbia's proposed SFV rate design on elderly and low income customers and the alleged deficiencies in that rate design approach relative to the Company's current volumetric-based rate structure.

Q: How is your rebuttal testimony organized?

A. My rebuttal testimony consists of this introductory section and the following additional sections:

- Summary of Findings and Recommendations
- Industry-Wide Activities Related to Utility Rate Design
- Principles of Sound Rate Design
- Fixed Cost Allocation and SFV Rate Design
- Low Income and Elderly Natural Gas Consumption
- Bill Impacts Under SFV Rate Design
- Declining Use per Customer
- Risk and Return
- The Economics of Pricing
- Benefits of SFV

__Summary of Findings and Recommendations__

Q: Can you briefly summarize your findings and recommendations related to these parties' presentations?

A. Yes. Based on my review of the points and underlying support presented by witnesses Brockway and Watkins concerning the Company's proposed SFV rate design proposal, I have reached the following findings and recommendations:

1. The Kentucky Public Service Commission (the "Commission") should reject the rate design recommendations of AARP and OAG for the Company's General Service - Residential rate class because they are based on incorrect analyses, faulty economics, and fail to satisfy fundamental regulatory principles that form the foundation for sound utility ratemaking.
2. This Commission should reject the contention made by Ms. Brockway that "most customers will be adversely affected" by the Company's SFV rate design proposal.
3. This Commission should reject the contention made by Ms. Brockway that the Company's proposed SFV rate design will disproportionately harm low income and elderly, low-use customers because her conclusions regarding gas consumption by these groups are unsupported.
4. This Commission should reject the recommendation made by Mr. Watkins that the Company's current customer charge be maintained and that any increase in the overall residential revenue responsibility be collected from the volumetric usage charge. This proposal is seriously deficient for a number of important reasons:
    a) It ignores the margin losses experienced in the Company's residential rate class caused primarily by declining use per customer and variations in weather from normal levels, thus depriving the Company of a reasonable opportunity to earn its allowed return on investment;
    b) It is not reflective of the true costs of serving the Company's residential customers;

c) It will perpetuate the intra-class cross subsidies that exist within the Company's General Service - Residential rate class -- which means that some customers will continue to overpay for gas delivery service while others will continue to underpay resulting in rates that are unduly discriminatory; and

d) It will not provide an appropriate ratemaking foundation for the Company to offer energy efficiency and conservation programs for the benefit of its customers because of the disincentive the Company has to promote such programs caused by revenues and sales that are directly linked through increased emphasis placed on a volume-based rate structure under the OAG's rate design recommendation.

5. Actual customer data derived from the Company's billing records clearly indicates that its low income customers use <u>more</u> gas per customer, on an annual basis, than the average residential customer it serves. Therefore, under the Company's SFV rate design proposal, low income customers will receive distinct benefits.

As a result, I recommend that the Commission adopt the Company's SFV rate structure proposal for its General Service - Residential Rate Schedule.

<u>Industry-Wide Activities Related to Utility Rate Design</u>

Q: Are the rate design positions of AARP and the OAG consistent with the recent industry-wide activities related to ratemaking approaches for gas distribution utilities?

A. No. The positions of AARP and the OAG on rate design in this proceeding are essentially to maintain the status quo regarding rate design for the Company. This is contrary to the widespread and growing recognition and endorsement throughout the utility industry of ratemaking approaches that "decouple" a utility's sales from its revenues. In my opinion, such a ratemaking approach is becoming more widespread as its conceptual underpinnings gain acceptance by a greater number of utility regulators as the challenges in the utility industry become more evident and pronounced.

Q: What are the factors driving the widespread and growing level of interest in revenue decoupling?

A. I believe there are two key factors driving this interest in revenue decoupling. First, it is widely acknowledged by utilities, regulatory commissions, legislators, and other stakeholders that utilities have an inherent disincentive to facilitate customers' participation in government or utility-sponsored energy conservation and efficiency programs under the old ratemaking paradigm. This inherent disincentive is caused by the prevalence of volumetric-based rate structures for gas utilities that create a decline in non-gas revenues with a decline in customers' gas usage. Revenue decoupling removes this inherent disincentive as a necessary prerequisite to government or utilities offering energy conservation and efficiency programs to customers.

Second, as a result of the ongoing decline in use per customer, most gas utilities have experienced an under-recovery of non-gas revenues. This serious financial impact can be mitigated with revenue decoupling.

Q: Have other participants in the gas industry endorsed the concept of revenue decoupling to address these issues?

A. Yes. With the recent increased volatility in energy prices and the resultant unprecedented upward pressure being placed on customers' utility bills, many energy industry groups have publicly advocated a renewed focus on promoting cost-effective energy efficiency measures to help relieve these consumer burdens. These groups include the American Gas Association ("AGA"), the Natural Resources Defense Council ("NRDC"), the Alliance to Save Energy, and the American Council for an Energy Efficient Economy ("ACEEE"). These groups realize that a fundamental change must be made to the utility ratemaking process in order to achieve these consumer benefits. They have endorsed the concept of revenue decoupling as their solution to the problem.[1]

Q: Have any other industry organizations recognized revenue decoupling as a viable ratemaking concept to address these issues?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") has recognized that revenue decoupling as a ratemaking concept provides earnings stability for utilities and removes the disincentives for promoting energy conservation. In particular, NARUC made reference to the above-mentioned groups and stated that, "among the mechanisms supported by these groups is the use of automatic rate true-ups to ensure the

[1] Joint Statement of the American Gas Association and the Natural Resources Defense Council submitted to the National Association of Regulatory Utility Commissioners ("NARUC"), July 2004.

utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail sales."[2]

Q: Have any national policy initiatives been undertaken to address the deficiencies in traditional utility ratemaking?

A. Yes. The National Action Plan for Energy Efficiency[3] ("Action Plan") emphasizes the need to eliminate ratemaking and regulatory disincentives or barriers through its recommendation that utility regulators "modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments." Specifically, the Action Plan states that "removing the throughput incentive is one way to remove a disincentive to invest in efficiency." It is widely recognized that SFV rate design or a revenue decoupling mechanism are ratemaking approaches that can address the "Throughput Incentive" utilities have when their rates are designed so that fixed costs are recovered through volumetrically-based energy charges.

Q: Does the Energy Independence and Security Act of 2007 address revenue decoupling in conjunction with the Act's directives on utility energy efficiency programs?

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[2] NARUC Resolution on Gas and Electric Efficiency, Sponsored by NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, Committee on Energy Resources and the Environment, adopted by the NARUC Board of Directors on July 14, 2004.

[3] Issued in July 2005, the "Action Plan" was facilitated by the U.S. Department of Energy and U.S. Environmental Protection Agency with the participation of over 50 utilities, public utility commissions, energy consumers, and non-governmental groups to set a broad course for encouraging greater energy efficiency investment in the United States.

A. Yes. Section 532(b) (6) (A) of the Act states that "the rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency." Further, from a policy perspective, the Act directs each state regulatory authority to consider "separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer." Clearly, SFV rate design and revenue decoupling mechanisms are two ratemaking approaches that do achieve this policy objective.

Q: Does the American Recovery and Reinvestment Act of 2009 address the concept of revenue decoupling within the context of the energy efficiency initiatives delineated in the Act?

A. Yes. The Act specifically states that the applicable State regulatory authority will seek to implement a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently.[4] This alignment can be achieved by a utility and its stakeholders through the implementation of SFV rate design.

<u>Principles of Sound Rate Design</u>

Q: Does the Company's SFV rate design proposal violate the Bonbright criteria referenced by Ms. Brockway at pages 6 and 12 of her direct testimony?

A. No. As I discuss below, SFV rates actually satisfy the Bonbright criteria more closely than the Company's current volumetric rate design. Specifically, Ms. Brockway concludes that the Company's rate design proposal violates the principles of public acceptability, stability (gradualism), and efficiency.

Q: Please briefly identify the Bonbright principles of rate design.

A. Simply stated, the Bonbright rate design principles or objectives that find broad acceptance in utility regulatory and policy literature include:

- Efficiency
- Cost of Service
- Value of Service
- Stability
- Non-Discrimination
- Administrative Simplicity
- Balanced Budget

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in his widely recognized, utility ratemaking treatise, Principles of Public Utility Rates. Each of these principles plays an important role in analyzing SFV rate proposals. To understand the role these principles play, I discuss each of the principles below.

Q: Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital in-

[4] American Recovery and Reinvestment Act of 2009, Section 410 (a) (1).

vestment in customer facilities and facilitates the efficient use of existing pipeline, storage and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. SFV rate design represents the most efficient possible price for delivery service since once the service is available to a customer there is no additional cost for delivering additional units of commodity. Customers who decide to use gas service in a new facility or add gas service to an existing facility knows the cost of the delivery service with certainty and the Company knows the revenue available to support the investment. Volumetric rates fail this test because the marginal rate for delivery service exceeds the marginal cost for delivery service. There are simply no efficiency benefits from volumetric rates for natural gas delivery service.

Q: **Please discuss the cost of service and value of service principles.**

A. These principles each relate to designing rates that recover the total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

The calculation of a "true" cost of service is complicated by the fact that for network industries like the natural gas distribution industry, the provision of public utility service often involves joint and common costs which must be allocated (rather than directly assigned) to specific customer classes or rate schedules to develop a full cost of service study. While a good fully distributed cost of service analysis can be performed using principles of cost causation, informed judgment is nonetheless required to perform such a study. A fully distributed cost of service study, properly reflecting cost causation principles and employing sound methods, provides a reasonable tool for the allocation of the utility's total revenue requirement to customer classes (interclass distribution) and within the customer classes (intraclass distribution). SFV rate design satisfies the cost of service and value of service principles because it eliminates intraclass subsidies. As I will demonstrate below, the cost to provide gas distribution service for a residential customer is the same regardless of the amount of gas consumed by the customer. This result occurs from a combination of the minimum size of distribution main and service installed and the economies of scale associated with the delivery service. Volumetric rates fail this test because they create intraclass subsidies and do not properly reflect the actual cost of service.

Q: Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design. Percentage increases in a rate change, however, are not a viable measure of rate stability since a one cent increase to a one cent rate is a 100% increase even though the additional cost is just a penny. Measuring stability looks at both the percentage increase and the magnitude of the increase separate from the percentage increase. For gas service, it is also important to review the annual customer impact since bills vary significantly on a seasonal basis. SFV rates provide stability over time by limiting the frequency of rate cases. SFV rates also provide stability during the year by fixing the monthly cost of delivery service, thereby avoiding weather impacts on the distribution service. Finally, stability is accommodated in the Company's rate design proposal by phasing in the change from volumetric to SFV rates over a two year period.

Q: Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices be designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers in the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, the customer's type of meter and service, demand characteristics, size, and a variety of other considerations are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. SFV rates eliminate the subsidies between customers within the residential class. Given the homogeneous nature of the residential class, the cost of providing delivery service to customers is the same regardless of the size of the customers. SFV rates recognize this cost equality issue within this rate class.

Q: Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff. SFV rates meet this requirement by fixing the price for delivery service permitting price transparency and easy bill calculations. In addition, customers will understand directly how colder weather impacts their bill by increased gas costs. Importantly, customers have accepted the concept of paying for the cost of widely available services through fixed charges, otherwise cell phone service and car rentals would be based on volume charges to attract and retain customers.

Q: Please discuss the principle of the balanced budget.

A. Finally, there is the critical principle that rate design permits the utility a reasonable opportunity to recover the allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates. SFV rates provide a natural gas utility with a reasonable opportunity to recover the authorized revenue requirement while volumetric recovery of fixed costs does not provide a reasonable opportunity.

Q: At times can the objectives embedded in these principles compete with each other?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q: Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between good price signals based on marginal cost and a balanced budget or the revenue recovery principle arises because marginal distribution cost is currently below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of providing delivery service access to the customer. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the revenue requirements while sending marginal cost price signals to customers related to consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges and the potential for revenue credits. In the case of a gas distribution utility such as Columbia, for residential customers, the combination of scale economies and class homogeneity permits the use of a single fixed monthly delivery charge that meets all of the requirements for an efficient rate and recovers the utility's embedded cost revenue requirement. For larger customers, a combination of these elements permits good price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge is not a concern.

Q. Does tension often arise between the rate design principles of cost of service and stability?

A. Yes. When subsidies exist in a utility's current rates, and new rates seek to eliminate the subsidy, there is the need to find a method to move to the appropriate cost-based efficient rate. In the case of SFV rates, both greater economic efficiency and the elimination of a significant intraclass subsidy result from its implementation. This creates differing impacts among customers within a particular rate class. As a result, the Company proposed to phase in over time the change to SFV rates. Since this is accomplished over two years, the benefits of setting the rates correctly, when weighed against the relative magnitude of the dollar impact for certain customers, represented the most reasonable ratemaking approach and will provide substantial benefits to customers overall.

Q: How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as the embedded customer, demand and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics and bypass alternatives; and
4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of under-utilized facilities, opportunities to offer new services, and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the actual billing determinants occurring during the test period used to develop the rates. The ultimate test of a rate from a market perspective is how well the rate recovers costs during the first twelve months after the effective date of new rates. This is referred to as the "Rate Effective Period."

Q: What advantages does the SFV rate design provide over other alternatives considered?

A. A SFV rate design offers advantages for both the Company and its customers that cause it to be a preferred approach. Customers benefit from the fixed rate simplicity. Customers understand that a single charge for delivery represents a common pricing method. Since this component of the bill does not change regardless of the weather, customers know the impact of additional gas use in cold weather represents the cost of the gas used. Customers benefit by knowing that a portion of their bill remains the same each month and that overall bills during the high cost winter months are lower as compared to bills under volumetric rates.

From an economic perspective, customers benefit from more efficient price signals and make more economically rational decisions related to energy conservation. Importantly, the elimination of volumetric rates for delivery service provides benefits to the customers least able to afford heat. The reason these customers benefit is that unlike volumetric rates, under SFV rates, customers' distribution bills will not increase as usage increases. And those customers have higher usage than average customers because of the relative inefficiency of their capital stock (i.e., heating equipment, wall and attic insulation, windows, etc.) and the resulting higher marginal use associated with colder weather.

<u>**Fixed Cost Allocation and SFV Rate Design**</u>

Q: At page 11 of her direct testimony, Ms. Brockway contends that the Company's cost of service studies, "support the observation that less than 100% of the Company's costs are in fact fixed, or a function of the number of customers." Do you agree with her contention that less than 100% of the Company's costs are fixed because of the manner in which its cost of service studies are conducted?

A. No. The allocation of costs based on demand within a cost of service study provides no evidence that the costs so allocated are not fixed, nor does the allocation of delivery costs on gas throughput imply that delivery costs are variable. It is obvious that no distribution costs are variable otherwise it would be appropriate to make pro-forma adjustments to delivery costs to reflect the assumption of normal weather. Regulatory commissions do not make such adjustments simply because it is well recognized that delivery costs are fixed in nature. Not only are distribution costs fixed costs, they are the same for all residential customers based on the minimum size of main and service installed. The reason that these costs are the same is based on the economies of scale in a gas delivery system. Since the Company uses a common size of two inches as the smallest size of main, I have analyzed the ability of a two inch main to serve the Company's residential customers using the system average density of 10 customers per thousand feet of main, the standard operating pressure of 60 pounds, and the standard pressure drop at the house regulator. By applying pipeline flow formulas, it is possible to determine the amount of gas that would flow through the pipe under design day conditions and to estimate the maximum demand that the pipe would serve. This type of analysis recognizes that there are substantial economies of scale associated with the gas distribution infrastructure such that the unit cost of capacity for gas delivery declines with size at a relatively rapid rate. Table 1 below illustrates this point. Columbia serves about 10 customers per 1,000 feet of main on average based on an average density within its service area of 53 customers per mile of main. This analysis shows that the minimum size of main will serve 20.2 Mcf of design day demand per customer.

Table 1 - Gas Distribution Scale Economies

Size of Main (inches)	Material Cost ($ per foot)	Installation Cost ($ per foot)	Total Cost ($ per foot)	Design Day Flow Capacity (Mcfd)	Unit Cost ($ per Mcfd)
2	$0.578	$7.37	$7.948	202	$0.039
4	$1.993	$8.40	$10.393	1,111	$0.009

Using a very conservative 20% annual load factor for residential customers, the two inch main would serve all customers using less than about 1,475 Mcf per year. Based on the

Company's annual bill frequency for its residential customers, the minimum size of main will serve virtually all of its residential customers on the gas system. Thus, it is reasonable to conclude that it costs the same, on average, to serve all residential customers regardless of demand. Ms. Brockway's concern for the allocation of demand plays no role in the costs of delivery service within the residential class. The allocation of demand is important for determining a reasonable share of total system costs within classes where larger sizes of main are installed producing economies of scale for all customers.

Q: Mr. Watkins expresses an opinion at page 28 of his direct testimony that recovery of fixed costs in a fixed, non-demand charge is not a true SFV rate. How do you respond to his opinion?

A. A true SFV rate uses one or more of the traditional rate components – a customer charge, a demand charge, or a commodity charge. The fixed components of the SFV rate may be either customer or demand charges. The proper use of these two components depends on factors such as the relative homogeneity of customers within the class and how costs vary within the class. Since it costs the same, on average, to serve every residential customer, there is no need to include a demand charge in the SFV rate applicable to residential customers. For larger classes of customers where there is less homogeneity of loads and of the associated costs, some combination of customer and demand charges are appropriate. For example, meter cost which is a customer-related cost increases as the size of the customer increases, and for the largest customers, it becomes unique for each customer. SFV rates often address this issue using graduated customer charges based on meter size. Where demand plays a role in the cost of local facilities, a demand charge may be appropriate within a class of large customers. Therefore, Mr. Watkins is simply wrong with respect to his definition of SFV rates.

Q: Mr. Watkins discusses the FERC permitting capacity release as a means of reducing fixed pipeline costs at page 30 of his direct testimony. Is this relevant for distribution fixed costs?

A. No. With respect to pipeline capacity release, there are other uses for the released capacity and the ability to release capacity allows those holding that firm capacity to sell the unused portion in other markets. There is no other use for the firm capacity to serve a residential customer and that customer, by virtue of connecting to the system, is responsible for the design day capacity dedicated to service for the customer. Since it costs the same for providing every customer with delivery service, it is both just and reasonable and economically efficient to recover the total fixed costs from the customer.

Q: On several occasions you have noted that residential customers are the same "on average." What does that characterization mean?

A. The reference to "on average" recognizes that even for a rate class that exhibits homogeneous load characteristics, the cost of assets can vary by the date of installation, by the location of the main (Mr. Watkins noted in his direct testimony that main costs vary by urban and suburban locations, for example), and by the length of the service line. Service line costs can vary depending on whether the customer is on the same side of the street as the main (a short-side service) or on the opposite side (a long-side service). However, it is not practical to determine cost for each customer based on vintage or which side of the street the customer is located. Hence, the use of average cost eliminates these types of unique issues and results in all residential customers having an equivalent delivery service cost equal to the average delivery service cost for the class.

<u>**Low Income and Elderly Natural Gas Consumption**</u>

Q: When discussing issues related to low income and low use customers and the Company's proposed SFV rate design, is it important to define terms precisely so that it is clear what the issues are and who may be affected?

A. Yes. In fact, for any discussion of energy policy issues, it is imperative that the use of a particular term be well defined. In this case, terms that describe certain types of gas customers often are used without careful definition. As such, inappropriate conclusions may be reached regarding the impact of the proposed SFV rate design on such customers.

Q: Please define the terms low use, low income, poverty, LIHEAP, and elderly as used in your discussion of the Company's gas customers.

A. Low use customers are those customers who use much less gas than the average for the utility's system. Low use customers are neither uniformly poor nor elderly or even low income. For example, elderly customers who live in a warm climate during the winter might be low use customers because they do not live in their residence in the winter and, therefore, do not heat the dwelling to a comfortable temperature. Such customers are not poor or even low income. Low income is an undefined term in the sense that there is no precise standard for low income. Presumably, low income means something much less than the median income of a group. Low income customers are neither uniformly below the poverty level nor low use customers. In addition, all elderly customers are not low income. In fact, for the state of Kentucky, over 71% of the elderly are above 150% of the poverty level. As with other terms, there is no specific age at which one is considered elderly, although those over 65 would generally be considered elderly. I say there is no specific age since many businesses provide elderly discounts, but may define elderly at a different age than 65. Elderly customers may be low or high income. Elderly customers may use more or less than the average amount of natural gas based on a number of factors beyond age. Poverty is a term defined by a combination of income and household or family size. For example, the median income for Kentucky in 2007 based on U. S. Census data was approximately $39,000. It is possible that a family with income greater than this median could be below poverty level because the family includes nine or more individuals. It is also possible that a single person making only $13,000, or one-third of the median income, would be 25% above the poverty level. LIHEAP is a federal program providing energy bill assistance to utility customers based on income and family size and may serve families up to 150% of the poverty level. LIHEAP customers represent a group with a well defined income and gas usage although not all LIHEAP recipients are below poverty level but, nevertheless, have been identified as being eligible for federal assistance.

Q: Does Ms. Brockway reach any conclusions related to gas consumption by low income and elderly customers?

A. Yes. At page 5 of her direct testimony, Ms. Brockway concludes that, "shifting costs over to a flat monthly charge will hurt many customers with usage below the median. This group includes households headed by persons aged 65 and older, who typically use less energy, on average, than households headed by younger persons." Ms. Brockway further discusses her conclusion that low income and elderly gas usage is below average at pages 6 and 7 of her direct testimony.

Q: Is Ms. Brockway's conclusion valid?

A. No. As I discuss below, the conclusion reached by Ms. Brockway is not valid for Columbia and suffers from a variety of infirmities regarding the underlying data upon which she based her conclusion.

Q: Is Ms. Brockway's use of a Census Division, such as the East South Central Division, a valid basis for drawing conclusions about the state of Kentucky or the Company's specific service area?

A. No. The East South Central Division includes the states of Kentucky, Tennessee, Alabama, and Mississippi. The Residential Energy Consumption Survey ("RECs") for 2005 reports in Table SH10 that the average Heating Degree Days ("HDD") for customers using natural gas in the East South Central Division is 3,504 HDD. This sharply contrasts with the state of Kentucky at a level of 4,370 HDD in 2007-2008, and with the Company's normal weather level of 4,648 HDD. The higher HDD in the Company's service area means that a greater portion of its customers' total gas consumption is heat sensitive compared to that of the average customer in the East South Central Division. Given the relative homogeneity of service area specific data derived for a particular utility, such data is far more reliable for determining the gas usage characteristics of various subgroups of customers within that same service area than a regional data base that includes household, income, and gas usage data spanning four different states.

Further, based on a review of the data Ms. Brockway utilized and my analysis of the raw data for the East South Central Division, the weighted average HDD for elderly customers in the sample is 3,238 HDD, lower than both the average of the overall sample (7.6% lower) and the specific level for Columbia. Similarly, the weighted average HDD for households with incomes below 150% of the poverty level in the sample is 3,223 HDD, lower than both the average of the overall sample (8.0% lower) and the specific level for Columbia. Since these two household subgroups have lower HDDs than the average household reflected in Ms. Brockway's data, the other groups must be higher than the average creating a significant gas usage difference based solely on HDD. This material difference in HDD among households is not present in Columbia's service area. Based on the AARP response to Columbia's First Data Request Question No. 1, Ms. Brockway provided gas consumption data for elderly and non-elderly households of 67.75 Mcf and 69.81 Mcf, respectively. Based on these numbers, the elderly households in the East South Central Division use just under 3% less gas than the non-elderly households, but have over 7% fewer HDD. Given this material difference in the key variable HDD, it is unreasonable to conclude that elderly households consume less gas than other customers in the Company's service area (where there are no such HDD differences) on the basis of the East South Central Division data used by Ms. Brockway.

Finally, there are other variables that impact customer gas consumption that must be considered.

Q: What variables does the Energy Information Administration ("EIA") consider in estimating residential energy consumption?

A. The EIA has developed the Residential Demand Module of the National Energy Modeling System as a tool for estimating energy consumption by residential customers. The modeling effort uses four categories of variables to model energy consumption:

1. Economic and demographic effects;
2. Structural effects;
3. Technology turnover and advancement effects; and
4. Energy market effects.[5]

Structural effects include the mix of end-use services including gas heat, gas water heating, gas cooking, and gas drying. The mix of end-use services is a critical element since gas consumption is driven not only by space heating, but the existence of other gas appliances as well. In addition, there are other factors that relate to the housing stock included in both economic and demographic effects and technology turnover and advancement effects. These other factors include dwelling type (single family home, apartment, etc), occupants per household, appliance stock, and efficiency of the thermal envelope created by the dwelling's physical structure. As a practical matter, larger homes built with newer technology use less energy in total for space heating and water heating (the two largest applications of gas appliances) than do smaller older homes with less efficient appliances and a less efficient thermal envelope.

Second, factors other than house size impact gas consumption for heating. For example, the age of the occupants impacts gas consumption. Older citizens often require

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[5] The National Energy Modeling System: An Overview 2003, Report #: DOE/EIA-0581

more heat to be comfortable in the winter. Families with younger children typically have more heat exchanges per day than average because of the number and duration of time that doors are opened by dwelling occupants. These usage and demand determining variables contribute to differences in household consumption and demand. Thus, it is unreasonable to rely on data for an entire Census division to draw conclusions about relative natural gas consumption for elderly customers within a utility's specific service area.

Q: Does data from the 2005 Residential Energy Consumption Survey support your contention that newer homes use less energy than older homes?

A. Yes. Table 2 below provides the Consumption Intensity by Main Space Heating Fuel Used by year of construction. The measure of intensity controls for both the heated square footage of the dwelling and the HDD. The natural gas intensity measures the end use consumption for natural gas for the unit divided by HDD times the ratio of heated square feet divided by 1,000. As the Table illustrates, both older and smaller homes consume more natural gas than larger newer homes.

Table 2 - Natural Gas Consumption Intensity by Year of Construction

Year of Construction	Heated Square Feet	Natural Gas Intensity
Before 1940	1,586	8.533
1940-1949	1,456	7.504
1950-1959	1,458	7.274
1960-1969	1,470	7.149
1970-1979	1,404	6.787
1980-1989	1,569	5.435
1990-1999	1,959	4.152
2000-2005	2,117	3.623

Source: 2005 Residential Energy Consumption Survey Table SH12- Consumption Intensity by Main Space Heating Fuel Used, 2005 and Table HC1.12 Housing Unit Characteristics by Average Floor Space, 2005

In some cases the differences are quite dramatic with homes built after 2000 using less than half the natural gas per square foot for the same HDD as homes built before 1960. Even among newer homes, homes built after 2000 use only 87% of the natural gas of homes built a decade earlier.

Q: Is there evidence that elderly consumers use more natural gas than other customers?

A. Yes. Elderly customers are more likely to live in older homes as Table 3 illustrates below. This Table shows that 68.4% of elderly households occupy housing units built before 1980 while only 56.7% of non-elderly households occupy housing units built before 1980. In addition, data from the 2005 Residential Energy Consumption Survey for elderly natural gas consumption intensity shows that in households with an adult age 65 or older, the natural gas energy intensity is 7.509 compared to 5.922 for households with no adults over age 65.[6]

Table 3 - Percentage of Housing Units by Year of Construction and Age of Occupant

Year Built	Before 1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2005
Age Under 65	12.7	6.2	10.3	10.3	17.2	17.4	16.6	9.2
Age Over 65	14.6	8.3	14.6	14.2	16.7	14.2	11.7	4.6

[6] 2005 Residential Energy Consumption Survey, Table SH12- Consumption Intensity by Main Space Heating Fuel Used, 2005

Source: 2005 Residential Energy Consumption Survey Table HC 5.3- Household Characteristics by year of Household Construction Unit, 2005

Q: What conclusions can you reach from the data discussed above?

A. The data illustrates that Ms. Brockway has relied on overly generalized data for analyzing the relationship between age and gas consumption by not controlling for HDD or other important variables that determine natural gas use. There is no reason to believe that elderly customers on average will be harmed by implementing SFV rates. In fact, there are strong reasons to believe that elderly customers will benefit from a fixed monthly payment for delivery service because fixed payments stabilize their bills, avoid higher bills in some months that have heating loads, and allocate costs more fairly based on their gas use.

Q: Does Ms. Brockway provide any specific data to support the contention that low income customers use less gas than non-low income customers?

A. No. Ms. Brockway asserts that data from the East South Central Division shows that low income customers use less gas than non-low income customers. However, no specific data was provided to support her conclusion. In addition, at page 7 of her direct testimony, Ms. Brockway asserts without any support that the finding that low income customers have higher than average use of natural gas is "contrary to other sources of data on home energy usage by age and poverty." Importantly, as noted above, poverty and low income are not precisely the same in that low income customers may even be above 150% of the poverty level for a small household.

Q: Is the use of a Census Division, such as the East South Central Division, a valid basis for drawing conclusions about the state of Kentucky or the Company's specific service area?

A. No. As noted above with respect to the East South Central Division, there is a significant downward bias in the HDD data relied upon by Ms. Brockway relative to the HDD levels for elderly customers and customers in poverty in the same Division, the state of Kentucky, and for the Company's specific service area. Without taking these significant HDD differences into account, any comparison of gas usage is flawed and cannot be the foundation for a valid conclusion related to the Company's specific service area.

Q: Given your concerns regarding the inapplicability of regional data to a specific utility service area, why were your discussions above based upon national data?

A. The purpose of my discussion above which relies on national data is to demonstrate that even the conclusions reached by Ms. Brockway based on regional data are further suspect because of other important factors that impact gas usage. Moreover, given the national data that identifies variables to determine gas usage for low income and elderly customers, it is entirely reasonable to accept the results of specific studies of utility service areas, such as those presented by Columbia, that show low income customers who might reasonably be considered poor customers use more natural gas than the average residential customer.

Q: Is there evidence presented by the Company in this proceeding that low income customers use more gas than the average customer?

A. Yes. The Company has provided LIHEAP data in the direct testimony of Mr. Mark P. Balmert that demonstrates low income customers use more natural gas than the average customer. This conclusion is also consistent with the data from the 2005 Residential Energy Consumption Survey when you examine data presented on a consistent HDD basis using gas consumption intensity data. Table 4 below provides consumption intensity by income level. It is reasonable to assume that households under $15,000 are both low income and below 150% of the poverty level. Both of these groups have natural gas intensity more than double those of the highest income groups.

In addition to the above data by income level, the same report provides data relative to the poverty line. For natural gas intensity related to the poverty line, households below 100% of the poverty line had an intensity of 10.336, at 150% of the poverty line the intensity is 8.347 and above 150% of the poverty line the intensity is 5.694..

Table 4 - Natural Gas Consumption Intensity by Household Income

Household Income	Natural Gas Intensity
Less than $10,000	9.959
$10,000-14,999	10.363
$15,000-19,999	8.566
$20,000-29,999	8.332
$30,000-39,999	6.514
$40,000-49,999	6.367
$50,000-74,999	5.701
$75,000-99,999	4.574
$100,000 or more	4.803

Source: 2005 Residential Energy Consumption Survey Table SH12- Consumption Intensity by Main Space Heating Fuel Used, 2005

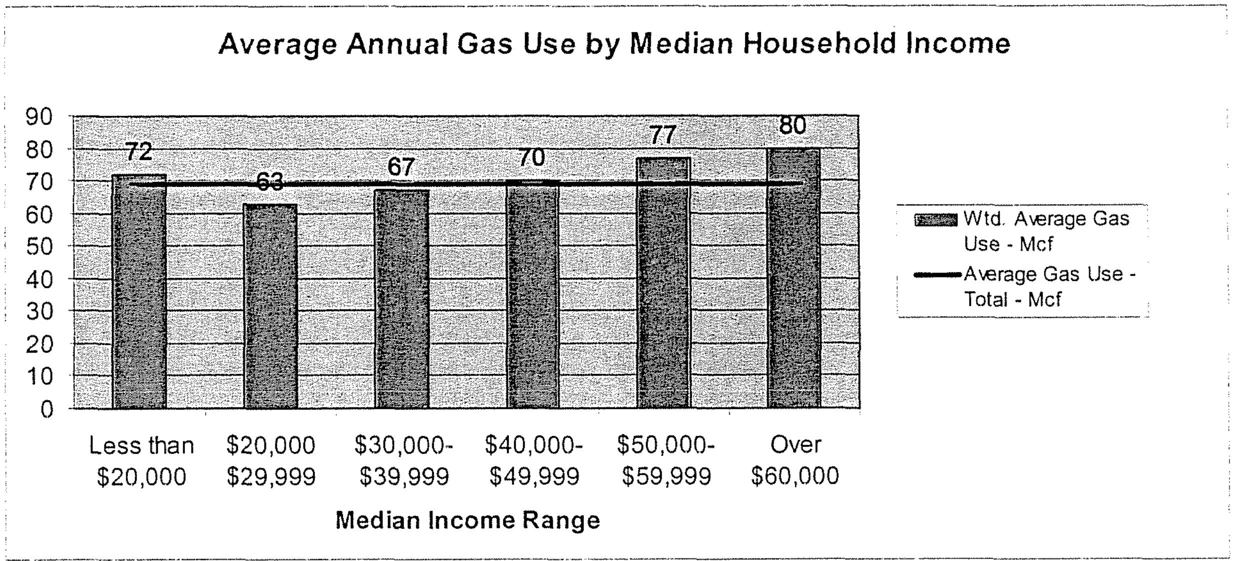
There is other data such as the age of the housing unit that also demonstrates low income customers may reasonably be expected to use more gas than the average customer. Approximately 69 percent of low income customers (defined as below 150% of poverty level) live in housing units built before 1980 compared to 56% of the non-low income population.

Q: Have you prepared any additional analyses of the relationship between income and natural gas usage for the Company's residential customers?

A. Yes. At my request based on my review of AARP's rebuttal testimony, the Company recently compiled gas consumption data for its service territory based on zip code. By correlating this data with income by zip code from the 2000 U.S. Census, I was able to compare average gas use per customer by zip code to median income for all of the zip codes reported in the Census data. Figure 1 below provides a summary of that data by calculating the weighted average gas usage for various median income ranges. The weighted Average Annual Gas Usage - Mcf is the Company's average annual gas use by zip code times the number of customers in each zip code, divided by the total number of customers in all zip codes within an income range.

It is important to note that most customers in the income range of $10,000 to $19,999 would be defined as poor customers based on poverty guidelines. For higher income levels between $20,000 and $40,000, only a decreasing portion of those customers would be identified as poor based on the number of people in the household. Since lower income customers in these income blocks have much larger households than typical, it would be expected that their gas usage would be higher than the average for the entire income range.

Figure 1 - Income and Gas Consumption – Residential Class



As Figure 1 above shows, the lowest income customers actually consume more gas than all but the two highest income groups. In addition, those residential customers with less than $20,000 in annual household income use about 4.3 percent more gas than the actual class average amount of approximately 69 Mcf per year. Further, this data tends to confirm the Company's earlier conclusion based on LIHEAP data that low income (below the poverty level) customers on average use more natural gas then the average customer for the system.

Q: Does the EIA Residential Demand Module of the National Energy Modeling System provide a basis for understanding why low income customers use more natural gas on average than other customers?

A. Yes. As I discussed in relation to gas consumption for elderly customers, there are structural, technological and demographic factors that significantly impact low income consumption. For example, a recent National Regulatory Research Institute ("NRRI") report entitled "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements" by David M. Boonin states at page 8, "Consumption often depends on demographics other than income, such as family size; quality of housing stock; owners versus renters and whether the renter pays the electric bill directly; end uses such as water heating, cooking, and space heating; appliance efficiency; and age of householders." Although this statement was directed at electric usage, it applies directly to natural gas as well. The level of income for determining poverty level specifically incorporates family size. Table 5 below illustrates this relationship.

As this Table illustrates, low income determination relies heavily on family size. As a result, a family of two, such as a young couple just starting out that has an income of $25,000 would not be considered poor or low income while a couple with four children and the same income would be considered poor. It is obvious that all else being equal, the family of six would use more natural gas because of family size that impacts the number of heat exchanges from opening doors and from extra water heating usage. Moreover, low income households are more likely to live in older less efficient homes, have less efficient capital stock-furnaces, water heaters, thermal envelopes and other factors that impact usage. Thus, for the same level of HDD, the low income family (below the poverty level) would reasonably be expected to use more gas than the low income family (above the poverty level).

Table 5 - 2008 HHS Poverty Guidelines

Persons in Family or Household	48 Contiguous States and D.C.	Alaska	Hawaii
1	$10,400	$13,000	$11,960
2	$14,000	$17,500	$16,100
3	$17,600	$22,000	$20,240
4	$21,200	$26,500	$24,380
5	$24,800	$31,000	$28,520
6	$28,400	$35,500	$32,660
7	$32,000	$40,000	$36,800
8	$35,600	$44,500	$40,940
For each additional person, add	$3,600	$4,500	$4,140

Source: *Federal Register*, Vol. 73, No. 15, January 23, 2008, pp. 3971–3972

Q: At page 7 of her direct testimony, Ms. Brockway contends that the Company's conclusion regarding low income usage exceeding the average usage is contrary to other sources of data. How do you respond to this statement?

A. Without knowing what "other sources of data" Ms. Brockway is referring to, it is not possible to determine the veracity of her statement. While she did indicate that the National Consumer Law Center performed an additional analysis using the 2005 REC Survey, no details of that analysis or its results were provided in Ms. Brockway's rebuttal testimony or exhibits.

Q: Beside the studies presented by Columbia in this proceeding, have you prepared or reviewed other studies based on specific utility service areas that compare low income natural gas consumption to that of other residential customers?

A. Yes. I am aware of a number of other studies based on specific utility service areas that compare low income natural gas consumption to that of other residential customers. In a 2008 rate case filed by Columbia Gas of Ohio, Inc. (Case No. 08-0072-GA-AIR), the utility conducted a detailed analysis of the relationship between gas usage and the income levels of its residential customers by individual zip code within its service area.[7] The analysis related the actual gas consumption from the utility's billing records for its residential customers to the household income characteristics collected from the most recent U.S Census, by individual zip code within the utility's service area. The analysis resulted in a "u-shaped' income-consumption relationship indicating that household income and gas usage was not directly related. Instead, the lowest income customers (with a median annual household income of approximately $20,000) actually consumed <u>more</u> gas than other higher income groups, and <u>more</u> gas than the average residential customer in each of the two geographic segments of the utility's residential rate class. This low income group in the "North of Columbus" and "Columbus and South" regions used approximately 16% and 8% more gas, respectively, than that of the utility's average residential customer in each region.

In a late 2007 rate case filed by Vectren Energy Delivery of Ohio, Inc. (Case No. 07-1080-GA-AIR), the utility conducted a detailed study of income and gas usage derived from the block group level of income and usage based on the GPS location of me-

[7] Rebuttal Testimony of Russell A. Feingold, Columbia Gas of Ohio, Inc., Case No. 08-0072-GA-AIR, pages 17-19 and Schedule RAF-R-4.

ters.[8] The study showed that the lowest income consumers, under $20,000 per year, used more gas except by customers with annual incomes over $70,000. In addition, those residential customers with annual household incomes under $20,000 also used almost 9% more gas than the average residential customer.

In another 2007 rate case filed by The Peoples Gas Light and Coke Company (Docket Nos. 07-0241 and 07-0242 before the Illinois Commerce Commission), the utility presented the results of an analysis that concluded its low income residential customers consumed almost 22% more gas, on an annual basis, compared to the annual gas usage of its average sized residential customer.[9]

In a 2006 rate case filed by Missouri Gas Energy (Case No.GR-2006-0422 before the Missouri Public Service Commission), the utility had undertaken a study to ascertain the relationship between residential consumers' income levels and their usage of natural gas in its service territory.[10] The conclusion reached in that study was that: "the income-consumption relationship for residential natural gas usage was mildly 'U' – shaped: above average at the lowest income levels, declining through middle incomes, and then rising again to above average at higher income levels." At the lowest income levels, the average use per customer was almost 21% higher than the level for the average residential customer.

I should note that I appeared as the utilities' rate design witness in three of the four rate proceedings discussed above and am personally familiar with the studies filed in

[8] Rebuttal Testimony of H. Edwin Overcast, Vectren Energy Delivery of Ohio, Inc, Case No. 07-1080-GA-AIR, pages 12-16.
[9] Rebuttal Testimony of Valerie H. Grace, The Peoples Gas Light and Coke Company, Docket Nos. 07-0241 and 07-0242, pages 37-39, and Exhibits VG 2.8-PGL and VG 2.9-PGL.
[10] Rebuttal Testimony of Philip B. Thompson, Missouri Gas Energy, Case No. GR-2006-0422, Schedule PBT-2.

all the above cases. I relied upon the results of these studies to support the rate design proposals that were filed by the utilities in three of those rate proceedings.

Q: Please summarize your findings related to Ms. Brockway's conclusion concerning the gas usage characteristics of the Company's low income and elderly consumers?

A. Based on the above discussion, it is my opinion that Ms. Brockway's conclusions are not valid as applied to Columbia's specific service area. More importantly, based on the actual gas consumption and income data for the Company's service area, low income customers use more gas on average than non-low income customers. In addition, I have shown that elderly customers tend to live in older homes and use gas more intensely than other customers. As a result, low income and elderly customers will actually benefit from the implementation of SFV rates, contrary to the position of Ms. Brockway.

<u>Bill Impacts Under SFV Rate Design</u>

Q: Ms. Brockway contends at page 6 of her rebuttal testimony that under the Company's SFV rate design proposal most of the Company's residential customers will be adversely impacted because their gas usage is too low to benefit from the elimination of volumetric delivery charges. How do you respond?

A. Ms. Brockway's contention is incorrect and misleading because the number of customers that will experience larger rate increases due to the proposed implementation of an SFV rate design does <u>not</u> constitute "most" of the Company's residential customer base. The fundamental flaw with Ms. Brockway's argument is that her underlying bill impact analysis is incorrect. Specifically, Exhibit NB-3 presents bill comparisons under the

Company's current and proposed rates for various gas usage levels chosen by Ms. Brockway. This exhibit shows that for a customer with average annual gas usage of 72 Mcf, the customer's base rate bill would increase by about $72 per year once the SFV rate design in Year 2 was implemented. On the basis of these bill comparisons, Ms. Brockway concludes that "most of Columbia's customers have usage below the level needed to benefit more from the elimination of volumetric charges than the increase they will see in monthly fixed charges, at the Company's proposed revenue level." Unfortunately, Ms. Brockway in Exhibit NB-3 has incorrectly attributed the increase in the average customer's bill to the SFV rare design when, in fact, the resulting rate increase for the average residential customer is caused solely by the overall revenue increase proposed by the Company for its residential rate class. Had Ms. Brockway chosen to isolate the bill changes caused by the SFV rate design from those caused by the Company's overall revenue increase request, she would have realized that the SFV rate design itself has no bill impact whatsoever on a residential customer that uses the average annual amount of gas for the class. In Exhibit NG-3, the resulting bill increase for the average residential customer presented by Ms. Brockway reflects only the impact of the Company's proposed overall rate increase of 9.93% to the residential rate class.

Q: **Can you illustrate the customer bill impacts of the Company's SFV rate design separately from the impacts caused by the overall rate increase to the residential class?**

A. Yes. Attachment RAF-1 presents a series of bill comparisons on a monthly and annual basis for a residential customer that uses approximately 69 Mcf per year – the average for the Company's residential class. Page 1 shows that the annual bill impact for the average residential customer is equal to 8.69% - which is almost identical to the proposed overall revenue increase of 8.65% (see Schedule M, page 1 of 2) for the Company's General Service - Residential rate class. Page 2 shows the same analysis with gas costs excluded to correspond to the way in which Ms. Brockway presented her bill comparisons in Exhibit NB-3. Page 3 shows the annual bill impact caused by the Company's SFV rate design for the average-sized residential customer. To exclude from this analysis the impact of the Company's proposed overall rate increase to the residential class; I developed a SFV rate design using the current non-gas revenues for the General Service – Residential rate class, excluding EAP Recovery revenues (see page 3 of Schedule M-2.2). This analysis shows that the SFV rate design has no impact on the annual bill for an average residential customer. This is not an unexpected result and it shows that the "breakeven gas consumption point" for the SFV rate design between a customer experiencing a rate increase or a rate decrease for delivery service is the gas usage of the average-sized customer in the class (approximately 69 Mcf). Ms. Brockway claimed a much higher "breakeven" gas usage level of 110.5 Mcf which she computed in Exhibit NB-3. Contrary to her finding, in general, a customer with greater than average gas usage level will experience a decrease in its annual gas bill under a SFV rate design and a customer with less than average gas usage will experience an increase in its annual gas bill. The magnitude of the change in the annual gas bill for any particular customer also will be a function of the customer's monthly pattern of gas consumption. As I explained earlier, these types of movements in customers' bills are consistent with, and supportive of, the rate adjustments necessary to reflect the fixed cost nature of the costs incurred by the Company to provide gas delivery service to its residential customers.

Q: At page 14 of her direct testimony, Ms. Brockway expresses a concern over the billing impacts for low use customers under the Company's SFV rates. Is this a significant issue?

A. No. Less than two percent of the Company's residential customers do not use gas for space heating. Nevertheless, the Company installs the same main, meter and regulator to serve the customer. In addition, the Company installs the same service line for the customer, albeit there may be a contribution required based on the length of the service line pursuant to the Company's line extension policy. In addition, the Company incurs the same customer related costs for these customers. If these customers were paying the actual cost to provide delivery service, they would pay the same as all other customers. Since they are not paying the full cost of service, they are being subsidized by other customers. There is no reason to perpetuate this cross subsidy under the Company's current volumetric-based delivery service rates.

Q: How do the Company's low use residential customers compare in number and size to the remainder of its residential customer base?

A. Page 1 of Attachment RAF-2 presents a graphic representation of an annual bill frequency for the Company's residential rate class for the twelve months ended July 2009. The graph plots the number of customers by their annual gas usage in increasing usage intervals. It should be noted that the customers reflected in this graph are full-year cus-

creases during those summer months under the Company's SFV rate design proposal?

A. That is true, but those large percentage increases in the summer months (resulting from the very low summer bills) will be offset by the bill decreases in most of the winter months when gas usage is higher. Page 1 of Attachment RAF-1 demonstrates that while averaged size customers will experience relatively larger bill increases in the summer months when their gas usage is lowest (an average increase of $14.53 per month during the months of May through September or less than $.50 per day in these months), under the rate design proposal of the Company, these customers will experience a much more moderate average monthly increase of $6.91, or 8.7 percent, on an annual basis. The bills of most customers will decrease in the winter months when bills are their highest, and bills will increase in the summer months when customers' bills are their lowest – which is one significant benefit of a SFV rate design. The summer bill increases are much less dramatic when one considers the actual dollar increase rather than the percentage increase.

Q: Could implementing SFV rates for the Company's residential customers cause changes in some customers' use of natural gas?

A. Yes. When customers are faced with the full cost of gas service, some customers will find alternatives more economic and would be expected to switch. Since the economics of natural gas service for such customers depended on a subsidy from other customers, all customers will benefit from more economic decisions going forward. Some low use customers will also find that adding natural gas consumption is also a more economic alter-