Book III

UGI CENTRAL PENN GAS, INC.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant To

Section 53.51 et seq of the Commission's Regulations

CPG STATEMENT NO. 1 – ROBERT F. BEARD
CPG EXHIBIT NO. 1 – RFB-1
CPG STATEMENT NO. 2 – DONALD E. BROWN
CPG STATEMENT NO. 3 – PAUL R. MOUL
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ORIGINAL TARIFF
CPG GAS – PA P.U.C. NO. 4

DOCKET NO. R-2010-2214415

Issued January 14, 2011 **Effective March 15, 2011**

CPG STATEMENT NO. 1 – ROBERT F. BEARD

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-2010-2214415
UGI CENTRAL PENN GAS, INC.	:	

DIRECT TESTMONY
OF ROBERT F. BEARD, JR. P.E.

CPG Statement No. 1

Rate Filing Overview
Gas Operations,
System Safety and Reliability,
Customer Service,
Integration of CPG into UGI, and
Large Commercial & Industrial Throughput

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Robert F. Beard, Jr. My business address is 2525 N. 12th Street, Suite 360 Reading, Pennsylvania 19612.

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

A. I am employed by UGI Utilities, Inc. ("UGI"). I am Vice President of Marketing, Rates and Gas Supply.

Q. What is your educational background?

A. I received a Bachelor of Science degree in petroleum and natural gas engineering, and a master's degree in management from the Pennsylvania State University. I am a registered Professional Engineer in Pennsylvania.

Q. Please describe your professional experience.

A. I have more than twenty years of experience in the natural gas industry. I was initially employed by Cabot Oil & Gas Company as an engineer responsible for drilling and natural gas production. After approximately one year in this position, I was employed by Penn Fuel Gas, Inc., which later became PPL Gas Utilities Corporation ("PPL Gas"). During my employment with Penn Fuel Gas, Inc. and PPL Gas, I was responsible for engineering and technical services, storage, transmission and distribution operations, gas control, marketing, safety and training.

When PPL Gas was acquired by UGI on October 1, 2008, I became Vice President of the Southern Region. In this role, I was responsible for all distribution operations, construction and maintenance for the Region.

In my current role, I oversee all activity related to UGI's activities in the areas of marketing, rates and gas supply.

Q. Mr. Beard, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following Exhibits: CPG Exhibit RFB-1 (a map of the Company's service territory). I am also sponsoring certain responses to the Commission's filing requirements. Each response identifies the witness sponsoring it.

Q. Please describe the purpose of your testimony.

A. My testimony serves several purposes. First, I will give a brief overview of the Company's need for rate relief in this case as well as an outline of the testimony being offered by the other UGI witnesses in this case (Part II). Second, I will generally discuss CPG's gas operations (Part III). Third, I will discuss CPG's safety record (Part IV). Fourth, I will describe CPG's customer service performance (Part V). Fifth, I will discuss the integration of CPG into UGI since CPG was acquired by UGI on October 1, 2008 (Part VI). Sixth, I will provide an overview of the adjustments to CPG's Large Commercial and Industrial ("Large C&I") throughput, including the potential threat of bypass related to Marcellus Shale gas production (Part VII).

II. OVERVIEW OF THE NEED FOR RATE RELIEF

Q. Please discuss the rate relief that CPG is requesting through this filing.

A. CPG is seeking an increase in its annual base rate operating revenues of $16.46 million, or 15.4 percent, on a total revenue basis, with a proposed effective date of March 15, 2011. The Company is also seeking authorization to make substantial changes to its existing tariff in order to harmonize CPG's tariff with those previously approved by the Commission for UGI and PNG. The Company also is proposing a significant new energy conservation program, the Energy Efficiency and Conservation Plan ("EECP"). Finally, the Company is proposing an incentive program to encourage the use of vehicles fueled by natural gas.

Q. Why is CPG seeking a rate increase at this time?

A. CPG's current rates do not provide it with a reasonable opportunity to earn its cost of capital. Since its last rate case in 2009, CPG's plant in service has increased by 5 percent, through investments in new and replacement gas plant. Further, CPG has granted its employees modest annual wage and salary adjustments and will continue to do so. Although CPG has been exercising cost containment measures and has made substantial progress toward integrating the operations of CPG with UGI Utilities and UGI PNG, those factors, along with experienced and anticipated declines in per customer usage, have caused CPG to be unable to earn a far rate of return on its investment, at present rate levels.

Specifically, as reflected in CPG Exhibit A (Future), Schedule A-1, CPG's operations are projected to produce an overall return on rate base of 5.02%, and a return on common equity of only 3.95%, for the twelve months ending September 30, 2011. As CPG witness Paul R. Moul discusses in his testimony (CPG St. 3), those returns are not adequate based on applicable financial data and the risks confronted by CPG. Unless CPG receives the proposed rate relief, those returns will continue to decline and potentially jeopardize its ability to make needed system investments to enhance the capacity of its distribution system and to replace older, obsolete facilities, each of which is needed to ensure continued system reliability and customer service performance and to better deal with the effects of the ongoing economic downturn. The drilling and production activity in the Marcellus Shale will bring about both opportunities and challenges for CPG. As more Marcellus production becomes available, our customers should benefit from lower cost gas. One challenge for the Company will be to balance the benefit of locally produced gas with the capital investments required to bring this gas into the CPG system. Also, the availability of cheaper, locally produced gas will likely expose the company to the risk of by-pass by some of larger customers.

Q. Why is the Company proposing an energy conservation program?

A. The Energy Efficiency Conservation Plan (EECP) will provide customers with a financial incentive to install higher efficiency gas burning appliances and equipment. This reduction in consumption will provide savings to customers who take advantage of the program and will place downward pressure on natural gas prices to the benefit of all customers. A more detailed discussion of this program is provided in the testimony of Mr. Fitzpatrick and others.

Q. Please identify the other witnesses providing direct testimony on behalf of CPG in this proceeding and the subject matter of their testimony.

A In addition to me, the following witnesses are providing testimony in support of the CPG's rate request:

Donald E. Brown (CPG St. 2) serves as the Vice President — Finance and Chief Financial Officer at UGI Utilities, Inc. Mr. Brown addresses CPG's accounting and budgeting processes. Mr. Brown also presents CPG's overall future test year revenue requirement, including all rate base claims, operating expense claims, and certain pro forma adjustments. Mr. Brown also presents CPG's historic year results of operations and rate base with adjustments to place them on a ratemaking basis.

Paul R. Moul (CPG St. 3) is the Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony concerning the overall rate of return that CPG should be afforded a reasonable opportunity to earn on its rate base investment. Mr. Moul also supports the Company's claimed capital structure, its embedded cost of debt as well as its requested return on common equity. Schedules and work papers supporting Mr. Moul's findings are set forth in Exhibit B.

Paul J. Szykman (CPG St. 4) serves as Vice President — Rates. Mr. Szykman is responsible for all areas of CPG's rate design and revenue allocation. Mr. Szykman also addresses and sponsors related exhibits showing the proof of revenues and proposed rate design. Finally, Mr. Szykman also is responsible for CPG's pro forma future test year operating revenue claim, including related adjustments to the future test year budget.

David Lahoff (CPG St. 5) is the Manager – Special Projects for UGI. Mr. Lahoff is sponsoring Exhibit F, which is Supplement Original Tariff – Gas Pa. P.U.C. No. 4 (“Tariff No. 4”). Mr. Lahoff provides a summary of the proposed changes to the tariff rules and regulations included in CPG’s proposed Tariff No. 4, and changes to the Choice Supplier Tariff, which is being incorporated into Tariff No. 4. Mr. Lahoff also provides an explanation of the Energy Efficiency & Conservation Rider (“EEC”), Conservation Development Rider, and the Natural Gas Vehicle Pilot program and service included in CPG’s proposed Tariff No. 4.

John Wiedmayer (CPG St. 6) is Project Manager of Gannett Fleming Valuation & Rate Case Consultants ("Gannett"). Mr. Wiedmayer develops and supports the Company's claim for annual depreciation expense and the accumulated depreciation reserve. His studies are presented in CPG Exhibit C (Future) and CPG Exhibit C (Historic).

Paul R. Herbert (CPG St. 7) is Gannett's President. He has prepared and sponsors a fully allocated cost of service study for use in this case, which is found in CPG Exhibit D.

Chris Rossi (CPG St. 8) is Manager, Customer Accounting Services. Ms. Rossi will explain the Company's Universal Services Program and Quality of Service Performance metrics.

Paul Raab (CPG St. 9) is an economic consultant and Partner in Energytools, llc. Mr. Raab will explain the development of and cost-benefit analysis supporting CPG's Energy Efficiency and Conservation Plan ("EECP").

Brian Fitzpatrick (CPG St. 10) is Manager – Energy Efficiency and Conservation at UGI Utilities, Inc. Mr. Fitzpatrick will discuss the reasons supporting CPG's proposed EECP.

Charles Weekes (CPG St. 11) is Director – Reporting and Budgeting at UGI Utilities, Inc. Mr. Weekes will discuss the Company's pro forma operating expenses and adjustments thereto.

Matt Nolan (CPG St. 12) is Controller at UGI Utilities, Inc. Mr. Nolan will discuss the Company's pro forma taxes and consolidated tax adjustment.

III. CPG'S GAS OPERATIONS

Q. Please provide an overview of CPG's operations.

A. CPG provides natural gas service to approximately 75,650 customers located throughout an 8,010 square mile service territory that is located in 35 counties in Pennsylvania. The service territory, for the most part, is sparsely populated and non-integrated, as it is composed of mostly rural or distant suburban communities.

Q. How does the non-integrated nature of the CPG service territory affect its gas system operations?

A. The CPG system is composed of a number of operating systems with historical roots in separately created gas distribution businesses. While CPG has consolidated the operations of numerous predecessor companies under one corporate entity, the gas systems of many of those predecessor companies remain physically separated from the others due to geographic distance. Operating remote, non-integrated gas transmission and distribution systems presents some unique challenges. Because of the remote nature of some CPG facilities, the number of customers served per mile of pipeline is relatively low. This lower customer density requires more operating and maintenance activity per customer. In addition, the remoteness of some CPG facilities presents challenges with regard to emergency response. As mentioned below, despite the challenges, CPG continues to provide safe and reliable service to its customers.

Q. Please discuss the physical separation of the operating systems.

A. CPG Exhibit RFB-1 is a map of the CPG service territory. Shown in blue are operations in 35 counties in Pennsylvania and one county in Maryland. Prior to CPG's acquisition by UGI, these operations were separated into 18 operating districts within Pennsylvania due to the non-contiguous nature of the service territories. Each operating district had its own operations center although, where practical, resources were shared across the districts in an effort to gain efficiencies. As the operating districts are physically separated by wide swaths of geography, there is little opportunity to operate them together as one would operate an integrated network of pipeline facilities. As a result, the opportunities to centralize certain field operations have been limited. However, as discussed below, wherever feasible, we are integrating the management of CPG's operations with UGI's and PNG's for the purpose of gaining economies of scale among the three companies.

Q. Please discuss the CPG transmission and distribution facilities.

A. CPG owns and operates approximately 3,800 miles of main, about 124 miles of which are classified as transmission lines. The vast majority (82%) of distribution main is constructed of contemporary material, which includes coated steel and plastic. With one exception explained below, the transmission lines are used in the various operating districts in our service territory to receive gas that is delivered by an interstate pipeline at higher pressure and/or to transport those gas supplies over significant distance to distribution market areas located in the service territory. Once the gas reaches the distribution market, it is regulated down to distribution system operating pressures and delivered to our customers through service lines owned by the Company.

Q. What is the exception you referenced?

A. I note that CPG presently owns the TL-94 line, which is a 10-mile transmission line that is utilized exclusively as part of the operation of the storage facilities in the Tioga West and Meeker Fields ("Storage Facilities") located in Tioga County, Pennsylvania. However, as explained in the direct testimony of Mr. Lahoff (CPG St. 5), the Storage Facilities, together with the TL-94 line, are being acquired by UGI Storage Company ("UGI Storage"), pursuant to an application filed with FERC at Docket No. CP10-23-000.[1] On October 21, 2010, FERC issued an Order approving, among other things, UGI Storage's application for approval to acquire the Storage Facilities and the TL-94 line from CPG. Once these assets

[1] In conjunction with this action, CPG filed a Petition with the Commission at Docket No. P-2009-2145774 seeking approval to reduce its base rates upon FERC approval of the transfer of the Storage Facilities and the TL-94 line. On September 28, 2010, the Commission approved a Proposed Stipulation to Resolve All Outstanding Issues resulting from CPG's Petition, and ordered CPG to file a compliance tariff supplement implementing the terms of the Stipulation as modified effective on one-day's notice following FERC's issuance of a certificate of public convenience authorizing UGI Storage to acquire the Storage Facilities and the TL-94 line.

are transferred, CPG will no longer own and provide transmission services through the TL-94 line.

Q. How does CPG staff its gas operations?

A. CPG has 198 full-time employees. Of that number, more than half of are represented by a union, and the remaining employees are salaried or hourly, non-union employees. More than half of these employees are involved in the physical operation and maintenance of the transmission and distribution facilities, which includes the construction, operations and maintenance of mains, services and other facilities, damage prevention and safety, and pipeline regulatory compliance. The remaining employees are responsible for administrative duties, marketing, customer service, and credit and collections. In addition, as discussed in more detail below, CPG benefits from various management and support services provided by UGI and UGI Corporation (*e.g.*, finance and accounting, payroll, gas supply, engineering, rates, purchasing, fleet, insurance, legal, treasury operations, corporate governance, information technology).

Q. How are the operations of CPG been integrated into those of PNG and UGI?

A. UGI has integrated several parts of the operations of UGI, PNG, and CPG into the UGI System's Northern and Southern regional operating areas. Generally, the Northern Region is composed of the entire PNG service territory, the portion of UGI's gas service area in and around Hazleton, the UGI Electric Division, and what were CPG's Northeast and Northwest Operating Regions. The Southern

Region is composed of the entire UGI gas system other than Hazleton, and what were CPG's Southeast and Southwest operations.

Q. With this operational integration, who is responsible for the overall management of the gas system operations?

A. The Vice President of Operations is responsible for overseeing all operations. Reporting to the Vice President - Operations, the Vice President - Northern Region and the Vice President - Southern Region are responsible for each of the operating districts located in their region and thus are responsible for the planning, operation, maintenance, and construction of the system. Supporting the regional operations is an organization led by a Vice President - Operations Planning and Implementation, who is responsible for standardizing work and construction practices, environmental issues, damage prevention, training and safety, and other support. In addition, the Director - Central Services is responsible for overseeing and managing the various customer accounting operations including Universal Services, call center operations, and other related functions for all of CPG, UGI (both the electric and gas divisions), and PNG. Among other positions, the Director - Engineering has responsibilities for the gas engineering activities for the three companies.

Q. Has this integration provided opportunities to integrate the pipeline networks of UGI, PNG, and CPG?

A. Yes. In an effort to provide an additional feed into the CPG Pittston system, an interconnection was established with the PNG distribution system. We continue to explore additional opportunities to establish interconnections between the UGI gas utilities companies as a means of providing a least-cost solution to supply and operational needs.

Q. What benefits have been realized as a result of the integration of departments/functions since the acquisition?

A. Since the acquisition of CPG, the Company has made good progress in integrating CPG, PNG and UGI, where it makes sense. CPG has been integrated into the UGI financial system so that financial data and reporting can be done consistently across all three companies. This consistency helps create more effective and efficient financial operations.

We also have integrated other critical areas of operation, such as safety, training, engineering and standards. Integration of these key areas enables the company to identify best practices and employing them across the companies. Standardization in areas such as design, methods and materials also facilitates efficiency and consistent operations.

Q. Are there other efforts to leverage synergies through consolidation or the sharing of best practices?

A. Yes. UGI has created a centralized materials and standards Department that focuses on best practices, standardization of operating practices and substructure damages. The goal of this department is to provide benefits to all UGI utility companies by reducing any costs associated with separately managing the companies. As part of this effort, we are looking for opportunities to further develop our workforce, where practical, by cross-training our staff to be capable of working on multiple systems.

Q. Have the operating cost reductions resulting from these efforts been reflected in CPG's budget in this case?

A. Yes, they have.

IV. <u>SAFETY AND SYSTEM RELIABILITY</u>

Q. Have CPG's safety programs been integrated with those of UGI and PNG?

A. Yes, they have. We have brought the safety programs under one umbrella. This enables the three companies to share best practices from an employee safety as well as a gas system safety perspective. The ability to leverage the combined experience of three gas companies has been very beneficial in our effort to identify and implement safety related best practices.

Q. Please discuss CPG's efforts to ensure gas system safety and reliability.

A. CPG monitors the condition and integrity of its pipeline system as mentioned above. Of the nearly 3,700 miles of distribution pipeline system, approximately 82% is comprised of newer, low maintenance materials (plastic or coated, cathodically protected steel). Based on a risk profile, or in connection with municipal infrastructure projects. CPG replaces older cast iron mains at a rate of about 3 miles per year and replaces bare steel main at approximately 9 miles per year,

Q. Please discuss CPG's efforts to manage the number of times its gas facilities are hit by third parties.

A. Since its integration with UGI and PNG, CPG has reduced its annual incident rate per thousand of locate requests by approximately 15% (2.7 to 2.3). Through the expansion of UGI's comprehensive Substructure Damage Database process to CPG and coupling it with the "Pipeline Education and Awareness Program" CPG hopes to further reduce its line hit rate to the performance levels of UGI Utilities, which was 1.5 in 2010. As noted by the PA PUC in a recent audit, these tools allow UGI to track and monitor various aspects of pipeline damage such as marked/unmarked hits, amount billed, amount collected, etc., and led to a reduction in the number of line hits on the UGI system. This process is led by a Manager of Substructure Damage and Best Practices along with a Coordinator of Substructure Damage having responsibility for UGI, CPG, and PNG. CPG and PNG have been integrated into UGI's comprehensive Substructure Damage Database and there will be a single "Pipeline Education and Awareness Program" consistently administered for all three companies.

Q. How is CPG’s performance in the area of gas odor response rate?

A. CPG continues to have a very favorable gas odor response rate. In 2010, CPG responded to 99.73% of all odor calls within one hour of receiving the call. Considering the size of the CPG service territory and the remote location of some customers, this gas odor response rate is very good.

Q. In your opinion, does CPG have a good history of employee safety?

A. Yes, it does. In 2010, the OSHA lost time rate for CPG was 0.44, a significant improvement over 2009 when this rate was 1.2. Additionally, the OSHA motor vehicle accident rate for 2010 was 2.8, compared to a rate of 5.8 in 2009.

V. CUSTOMER SERVICE PERFORMANCE

Q. Since the acquisition, has CPG maintained its historically high level of customer satisfaction?

A. Yes. CPG consistently scores highest among Pennsylvania's gas utilities in the Metrix Matrix transactional survey commissioned by the Pennsylvania Public Utility Commission. Additionally, CPG's solid customer satisfaction performance has contributed to UGI posting high scores in the JD Power survey which rates natural gas companies in the region. Additional detail regarding CPG's customer service performance is provided in the testimony of Ms. Rossi.

VI. COMMERCIAL AND INDUSTRIAL THROUGHPUT

Q. Have there been any changes to the Large Customer/Industrial Sales Budget since it was approved?

A. Yes, overall volumes have been reduced by about 11% from the original budget for customers being served on Rate L and 1.7% for customers being served on Rate GD.

Q. What is the basis for these proposed reductions?

A. The reasons are two-fold. First, we have evaluated the potential for customers to bypass the gas utility, a risk also quantified in the UGI 10-K report. Many of these customers are locked into long-term agreements for a significant portion of their load and represent little threat. However, approximately 1.1 million dekatherms were removed from the Rate L budget to account for seven customers who represent a significant bypass threat (either to interstate pipeline or local Marcellus production). These customers have no long-term agreement for committed volumes and are free to bypass the UGI system at any time. 0.4 million dekatherms were removed due to pipeline bypass threat and 0.7 million dekatherms were removed due to local bypass threat. This also resulted in a reduction in firm demand for the Rate L customer group of 3,484 dekatherms per day (350 attributed to pipeline bypass and 3,134 attributed to local production bypass).

Q. What is the second reason for adjusting the budgeted throughput for the large commercial and industrial market?

A. The remaining adjustment (an increase of 30,305 dekatherms for Rate L and a decrease of 49,018 dekatherms for Rate GD) results from updated information since the original budget was prepared. The Large Customer Budget (defined as customers served under Rates GD and L) is among the first to be created in the budget cycle. It is normally completed by June for the next Fiscal Year beginning the following October. Since the creation of the budget, there have been several changes among the group of customers. Several customers have terminated service due to business closures, some have significantly altered operations and one has significantly increased production. This more recent information has been reflected in our updated estimate.

Q. What is the margin impact of these changes?

A. Mr. Szykman will explain the effect of these changes upon sales margin.

<u>CPG Flex Rate Customers</u>

Q. Are there any customers that are currently being billed at less than maximum rates?

A. Yes, there are ten customers that are currently being billed at rates which are less than the maximum under the current tariff.

Q. In general, why are the rates discounted for these customers?

A. Customers sometimes require a discounted rate because they have competitive alternatives or other competitive issues. Competitive alternatives usually compete directly with utility provided natural gas and can be obvious, such as, being dual-fueled or being near an interstate transmission line or local production for a bypass. Competitive issues can be less obvious, such as an economic incentive to attract business to the region or a need for the customer to be price competitive with their product in the marketplace. From the utility perspective, any contribution to fixed costs that is above our marginal costs to operate the system is a benefit to all ratepayers. Certainly, this is true if the alternative is zero sales revenue from a customer.

Q. Is the Company proposing changes with respect to this group of customers as part of this case?

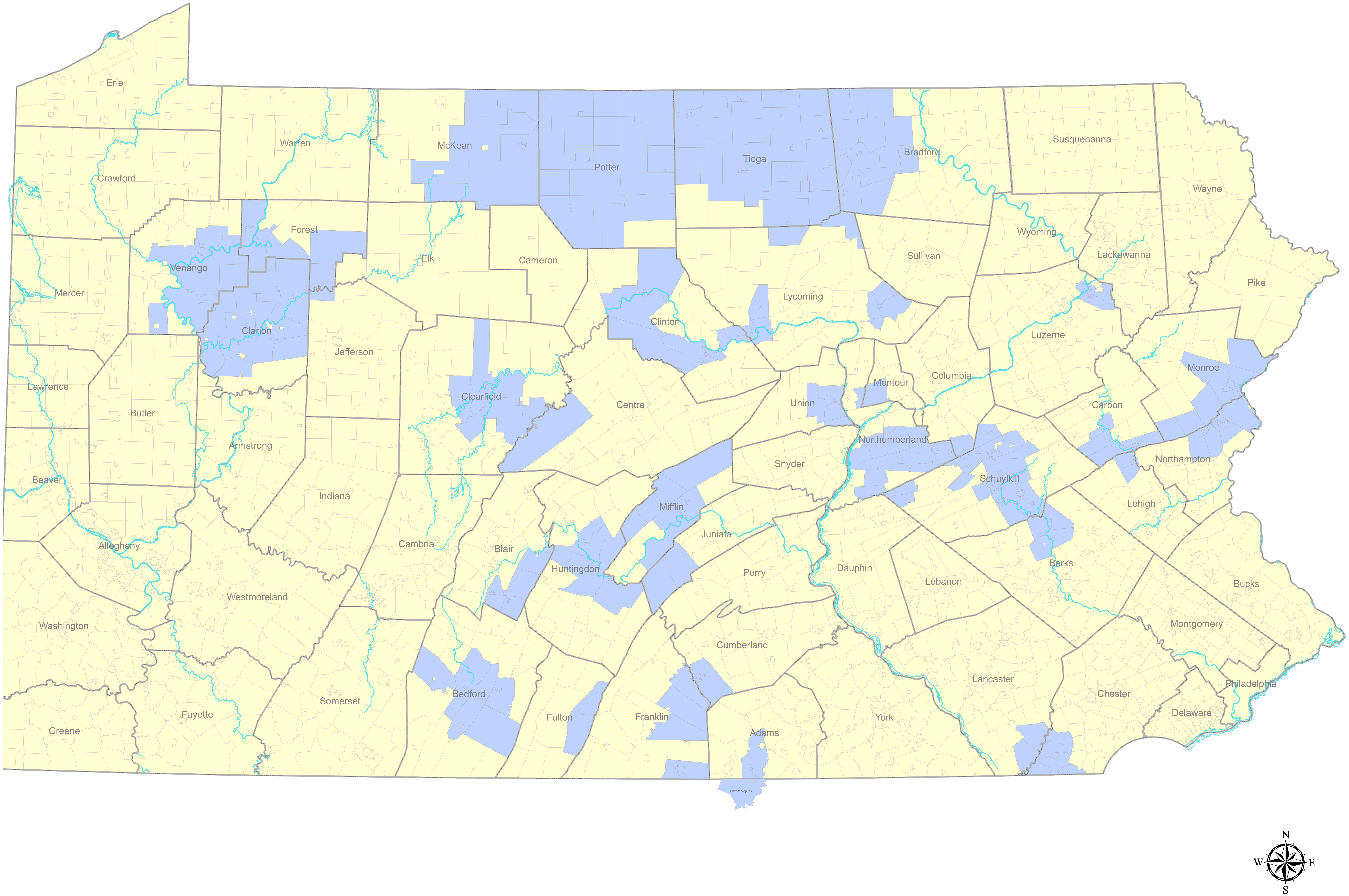
A. Yes. As explained in more detail by Mr. Szykman and Mr. Lahoff, CPG is proposing a substantial restructuring of its tariff in this proceeding to integrate it with tariff previously approved by the Commission for UGI Utilities and UGI PNG. Most of the customers referenced above, who are currently served under CPG's Rate L, will be served under proposed Rate XD.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CPG EXHIBIT NO. – RFB-1

CPG SERVICE TERRITORIES



SEPTEMBER 12, 2008

PRJ-1026-10

CPG STATEMENT NO. 2 – DONALD E. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
	:	
	:	
v.	:	Docket No. R-2010-2214415
	:	
UGI CENTRAL PENN GAS, INC.	:	

DIRECT TESTIMONY
OF DONALD E. BROWN

CPG Statement No. 2

Accounting and Budget Process
Rate Base

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Donald. E. Brown. My business address is 2525 North 12th Street, Suite 360, Reading, PA, 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI"). My title is Vice President — Finance and Chief Financial Officer.

Q. What are your principal duties and responsibilities as Vice President – Finance and Chief Financial Officer ?

A. In that capacity, I have overall responsibility for the finance and accounting functions for Central Penn Gas, Inc. ("CPG"), as well as its affiliated distribution companies, UGI, and UGI Penn Natural Gas, Inc. ("PNG"). My duties include the management of the financial planning, accounting, payroll, accounts payable and cash remittance functions for the distribution companies and coordination of those functions with the Chief Financial Officer of our ultimate parent company, UGI Corporation. In all my assignments, I report directly to the President and Chief Executive Officer of UGI and assist him in all financial matters pertaining to utility operations. I also am responsible for supervising the preparation and filing of regulatory reports with the Pennsylvania Public Utility Commission ("PUC"), Federal Energy Regulatory Commission ("FERC"), the United States Securities and Exchange Commission ("SEC") and the United States Internal Revenue Service ("IRS").

Q. What is your educational background?

A. I hold a Bachelor's degree in economics from the Wharton School, University of Pennsylvania and an MBA from the Fuqua School of Business at Duke University. I have completed various industry (*i.e.*, American Gas Association and Edison Electric Institute) and Company-sponsored workshops. I have also completed all of the requirements to become a Certified Public Accountant.

Q. Please describe your professional experience.

A. I joined UGI in August 2007, as the Controller of the Gas Division. Prior to joining UGI, I was the Director of Treasury Services at UGI Corporation and was responsible for cash management, bank relations and raising debt capital, supporting mergers and acquisitions, and investor relations. Prior to joining UGI, I spent several years at Constellation Energy and Progress Energy in various financial planning and strategic analysis roles in electric generation, wholesale and retail marketing and natural gas businesses. Earlier, I spent five years with Deloitte & Touche in its management consulting and tax functions.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes, on several occasions. These proceedings include the most recent base rate cases for CPG (Docket No. R-2008-2079675) and PNG (Docket No. R-2008-2079660).

Q. Please describe the purpose of your testimony.

A. My testimony has several purposes. I will explain the Company's accounting and budgeting processes (Part II). I also will discuss CPG's overall future test year revenue requirements presentation, including its principal accounting exhibits, all rate base claims, operating expenses claims and certain pro forma adjustments applicable to those areas (Part III). Finally, I will present CPG's historic year results of operations and rate base with adjustments to place them on a ratemaking basis (Part IV). This latter presentation is provided for comparative purposes only, as CPG has elected to determine its revenue requirement on a future test year basis.

Q. Mr. Brown, are you sponsoring any exhibits in this proceeding?

A. Yes. Together with other Company witnesses, I am sponsoring portions of CPG Exhibit A (Future) and CPG Exhibit A (Historic) regarding rate base and operating expenses. These exhibits comprise CPG's principal accounting exhibits for the future test year ending September 30, 2011 and the historic year ending September 30, 2010. The budget and actual data for the future test year and the historic year are derived from CPG's operating and capital budgets for the 12 months ending September 30, 2011 and book accounting data for the historic year ending September 30, 2010. I am also sponsoring certain responses to the Commission's filing requirements. Each response identifies the witness sponsoring it.

II. ACCOUNTING AND BUDGET PROCESS

Q. Please discuss CPG's accounting processes.

A. CPG's accounting records are kept in accordance with generally accepted accounting principles ("GAAP") and the FERC's Uniform System of Accounts adopted by the Commission. The Company also maintains a continuing property records system in accordance with applicable PUC regulations.

Q. Do CPG's continuing property records reflect the original cost value of the property in question?

A. Yes, they do. CPG's plant in service, plant additions, retirements and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts in accordance with PUC regulation.

Q. Are the books and records of CPG been subject to audit?

A. Yes. Historically, CPG's books and records were audited by internal and external auditors of its former parent company, PPL Corporation. Currently, UGI and UGI Corporation, and their external auditor, PriceWaterhouseCoopers, perform this function.

Q. How can you be reasonably certain that all of the property reflected in CPG's plant accounts is, in fact, used and useful?

A. CPG has in place a field process that requires that a record be created when property units are placed into service or retired. That information is then transferred through accounting entries to the Company's plant property accounts. Those entries reflect the addition or retirement and the original cost of any units of property that are added or retired. This process is reviewed by authorized individuals who review and approve the entries that are made to the plant property records. The process employed by CPG is the same as employed by UGI and PNG, the integrity of which has been reviewed by internal and external auditors.

Q. Please explain CPG's budgetary preparation and approval process.

A. Preparation of the CPG Operating Budget for the subsequent fiscal year begins during the spring. The revenue portion of the budget is a joint effort between the Marketing and Rates Departments. The Rates Department prepares the revenue budget from budgeted sales by customer class provided by the Marketing Department. The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, the cost of competing fuels, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the most recent year's usage trends adjusted to normal weather conditions, the price of competitive fuels relative to natural gas, and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management.

Concurrently, the expense portion of the Operating Budget is prepared. Employee levels are reviewed and appropriate staffing levels are set for the upcoming fiscal year. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, new or changed programs, and inflation. They are submitted for review and approval by senior management. CPG expenses are consolidated with allocated expenses from affiliated companies of CPG, such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing and from UGI Corporation to develop the budgeted Statement of Operations.

The Operating Budget is submitted to the President of the Company for his review and approval. As a final step in the budgeting process, the Operating Budget is submitted to the Board of Directors for its review and approval. Each element of the PNG Operating Budget is formulated by personnel responsible for that aspect of the operation and who will be held accountable for the accuracy of their forecasts. The first and primary use of the Budget is as a working tool for the management and planning of the business.

The CPG Capital Budget is prepared in conjunction with the Operating Budget. Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described and justified along with a breakdown of the costs associated with it. These projects are presented to the senior management which reviews them in terms of priorities, capital availability, and strategic alignment with the operating budget. After due consideration, the capital budget is set and presented, along with the operating budget, to senior management in a series of review meetings.

The Company utilized the CPG Capital Budget in order to develop its claim for plant in service as of September 30, 2010. As explained below, to calculate its claim, the Company adjusted the actual original cost of plant in-service recorded on its books of account at September 30, 2010, by adding and subtracting the estimated cost of additions and retirements budgeted for the future test year.

Q. Preliminarily, does the budget, and the various adjustments thereto discussed above, reflect any savings and costs associated with CPG's acquisition by UGI?

A. Yes, they do. UGI acquired CPG on October 1, 2008. Since that time, a number of efforts have been undertaken to integrate CPG's operations into the operations of the UGI utility and corporate systems. These efforts are discussed in detail in Mr. Beard's direct testimony (CPG St. No. 1). The revenue, expense, and rate base effects of these efforts are reflected in the 2011 budget used as the basis for developing the requested revenue requirement in this proceeding. As a result of these integration efforts, operating expenses have decreased 1.2% annually between 2009 and the 2011 budget. We have managed to decrease expenses despite annual increases in wages, pension and health care expenses.

III. <u>FUTURE TEST YEAR</u>

A. OVERVIEW

Q. How is your discussion of CPG's future test year revenue requirement presentation organized?

A. In Section IV.B, I will present a summary of CPG's future test year revenue requirement. In Section IV.C, I discuss how the Company's rate base has been organized and determined. In Section IV.D, I explain how the Company's revenues and operating expenses, depreciation and income taxes have been organized and determined.

Q. Please provide an overview of CPG's principal accounting exhibits.

A. CPG's principal accounting exhibit is CPG Exhibit A (Future), which includes a presentation for the future test year ending September 30, 2011. This presentation is comprised of four sections:

Section A summarizes CPG's requested rate base, revenues and expenses at present rates and the calculation of its requested revenue increase.

Section B includes basic accounting data extracted, in most part, from CPG's financial, accounting, operating and capital budgets, and other records. This data includes a future test year ending balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing CPG's embedded cost of debt, year end capital structure and overall claimed rate of return.

Section C provides the elements of CPG's rate base claim and how each element of that claim is derived. The Company's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory and offsets for accumulated depreciation, accumulated deferred income taxes, customer deposits and customer advances in aid of construction.

Section D presents the Company's revenues and expenses on a pro forma ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting test year expense and revenue levels are shown on Schedule D-3 and used to derive CPG's pro form income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in CPG Exhibit A (Historic)?

A. CPG Exhibit A (Historic) follows the format of CPG Exhibit A (Future) but reflects data for the historic year ending September 30, 2010. This information is provided in an effort to comply with the Commission's filing requirements. It provides a basis for comparing our future test year claims with actual book results from the historic year.

Q. From what sources are the data included in CPG Exhibit A (Future) and CPG Exhibit A (Historic) derived?

A. This data is derived from the Company's books and records and capital and operating budgets. CPG Exhibit A (Future) is based on adjusted budgeted data for the year ending September 30, 2011. CPG Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2010.

B. FUTURE TEST YEAR REVENUE REQUIREMENT

Q. How were the pro forma revenue increase and revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 4 of CPG Exhibit A (Future). Lines 1-11 summarize the pro forma measures of value (rate base). Pro forma revenues at present rates, pro forma expenses, and taxes at present rates, pro forma net operating income at present rates and the calculated rate of return at present rates are shown on lines 12-21. Lines 22-25 show the increase in net operating income required to permit CPG to earn its required overall rate of return of 9.11 percent. Application of the Gross Revenue Conversion Factor (GRCF) on line 26 establishes the revenue increase shown on line 27 needed to generate that net operating income. Column 5 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 6 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 9.11 percent.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $16.460 million. This represents the difference between the pro forma future test year revenue requirement of $123.312 million and the annual level of operating revenues of $106.852 million under existing rates. These figures are shown on line 15 of Schedule A-1 of CPG Exhibit A (Future).

C. RATE BASE

Q. With reference to CPG Exhibit A (Future), please explain how CPG's rate base values were determined.

A. The Company's rate base presentation is shown in CPG Exhibit A (Future), Schedule C-1. Schedule C-1 summarizes the Company's rate base values for the test year. Column 3 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 4-6 also show the amounts at present and proposed rates, respectively. CPG's total future test year rate base claim, net of deductions for accumulated deferred income taxes, customer deposits, and customer advances is $232.132 million. Except where otherwise noted, I will describe each of these rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how the Company determined its rate base value for plant in service.

A. The Company's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2010, and budgeted plant additions for the year ended September 30, 2011, less budgeted future test year plant retirements and pro forma plant adjustment shown on Schedule C-2.

Q. Please describe Schedule C-2 to CPG Exhibit A (Future).

A. This schedule includes 11 pages and presents CPG's total future test year claim of $347.164 million for gas utility plant in service on page 3, column 4, line 13. Gas utility plant enables CPG to provide gas service to its customers.

Q. How was the gas utility plant in service amount of $347.164 million, shown on Schedule C-2, page 3, line 13 determined?

A. This amount is based on the pro forma balance as of September 30, 2011. The amount includes: (1) utility plant in service as of September 30, 2010; (2) budgeted capital expenditures expected to close to plant for the 12 months ending September 30, 2011; and (3) an adjustment to remove non-jurisdictional plant, less plant retirements during the same period.

Q. Please describe what information is shown on Schedule C-2, page 3.

A. This information provides a summary of CPG's pro forma claim for utility plant in service by service category. Column 2 shows the future test year ending balances; Column 3 shows the net effect of the various plant adjustments; and Column 4 provides the adjusted future test year budgeted plant.

Q. What information is included on Schedule C-2, pages 4-7?

A. These pages show the gas plant in service balances for 2009 and 2010 plus the amount of plant additions budgeted as of the end of the future test year, by FERC account.

Q. Please describe the information shown on pages 8-9 to Schedule C-2.

A. The information shown on pages 8-9 reflect adjustments to plant that are being proposed by the Company, by FERC account.

Q. Please describe the adjustments reflected on pages 8-9 to Schedule C-2.

A. There are two adjustments as reflected in columns 2-3 of pages 8-9. First, the Company is removing non-jurisdictional plant located in Maryland. The second adjustment reflects the removal of CPG's storage facilities in the Tioga West, Meeker and Wharton Storage Fields ("Storage Facilities") from base rates. On November 19, 2009, UGI Storage Company ("UGI Storage") filed an application at FERC at Docket No. CP10-23-000 for a certificate of public convenience and necessity to acquire the Storage Facilities.[1] In conjunction with this action, CPG filed a Petition with the Commission at Docket No. P-2009-2145774 seeking approval to reduce its base rates upon FERC approval of the transfer of the Storage Facilities. On September 28, 2010, the Commission approved a Proposed Stipulation to Resolve All Outstanding Issues resulting from CPG's Petition,

[1] Concurrently with the filing of UGI Storage's Application, CPG filed an application with FERC at Docket No. CP10-24-000, pursuant to Section 7 of the NGA, seeking authorization to abandon that portion of the blanket certificate issued under 18 C.F.R. § 284.224 to its predecessor, North Penn, applicable to storage service, with such abandonment to take effect contemporaneously with the certificate approvals, if granted, requested by UGI Storage.

and ordered CPG to file a compliance tariff supplement implementing the terms of the Stipulation as modified effective on one-day's notice following FERC's issuance of a certificate of public convenience authorizing UGI Storage to acquire the Storage Facilities. On October 21, 2010, FERC issues an Order approving, among other things, UGI Storage's application for approval to acquire the Storage Facilities from CPG.

As a result of this transfer of the CPG's storage facilities to UGI Storage, $8.413 million of gas plant will be removed from rate base. The transfer is scheduled to be completed on April 1, 2011.

Q. Is the information for future test year retirements shown on pages 10-11 of Schedule C-2 to CPG Exhibit A (Future)?

A. Yes. Pages 10-11 of Schedule C-2 provide actual and projected plant retirements. Retirements for most plant accounts were projected by plant account by applying the average retirement, as a percent of additions, for the five years 2006 through 2010, to the future test year plant additions. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period.

2. Accumulated Depreciation

Q. Please explain how the Company determined its rate base value for accumulated depreciation.

A. Accumulated depreciation similarly determined, starting with accumulated depreciation as of September 30, 2010, adding the budgeted level of depreciation expense for the future test year and calculating the impact of the FTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in Mr. Wiedmayer's testimony (CPG St. 6), with the underlying future test year depreciation analysis provided in CPG Exhibit A (Future).

Q. Please describe Schedule C-3 of CPG Exhibit A.

A. This schedule, containing 11 pages, presents the accumulated provision for depreciation as of September 30, 2011, distributed among the various FERC accounts. The total amount for accumulated depreciation, $113.025 million, is summarized on pages 1-2 to this schedule. That amount is then reflected on line 2 of the measures of value summary on Schedule C-1.

Q. Please summarize the remaining 9 pages of Schedule C-3.

A. Page 3 shows the pro forma future test year level of accumulated depreciation distributed to the various plant categories, including the effect of pro forma adjustments related to the removal of the Maryland distribution facilities and storage facilities. Pages 4-5 show the detail of the accumulated depreciation by FERC account for the test year ending September 30, 2011. Pages 6-7 show the cost of removal amounts by FERC account. Pages 8-9 show the negative net salvage amortization by FERC account. Pages 10-11 include the salvage amounts for the test year. All of these amounts are included in the test year accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

3. Cash Working Capital

Q. Please explain how the Company determined its rate base value for cash working capital.

A. A detailed analysis of the Company's cash working capital ("CWC") requirements was conducted by the Company and is reflected in Schedule C-4. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the Company's payment of cash expenses incurred to provide that service, as shown in Schedule C-4.

Q. Please describe the Schedule C-4 of CPG Exhibit A (Future).

A. Schedule C-4 is a multi-paged document that presents the Company's claim for cash working capital ("CWC"). As shown on page 1 to Schedule C-4, CPG's CWC claim is $1.979 million. This amount is then reflected on line 4 of the rate base summary contained in Schedule A-1.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of CPG's revenue collection lag and overall expense payment lag. The revenue lag days are shown on line 1 and the expense lag days for each of the expense components are shown on lines 3-5. The net lag in the collection of revenue of 8.75 days shown on line 8 is then multiplied by the average daily operating expense balance on line 9 to arrive at a base CWC amount of $1.933 million for operating expenses. The average daily expense balance, $221,000 on line 9, is determined by dividing the total pro forma annual operating expenses, excluding uncollectible accounts expenses of $80.740 million on line 6, column 2, by the number of days in a year, 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe Schedule C-4, page 3, which shows the revenue lag calculation.

A. The total revenue lag days (line 23) were determined by dividing the average month-end accounts receivable balances for the thirteen months ended September 30, 2010 (line 17, column 2) into the annual revenue billed during the year ending the same date (line 18, column 3). This results in an accounts receivable turnover rate of 12.26 (line 19, column 4), which is equivalent to 29.77 lag days (line 20, column 5) (365 divided by 12.26 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 2.72 day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company and (2) the 15.21 day service lag, which is the time from the mid-point of the service period until the meter reading date. This calculation results in a total revenue lag of 47.7 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.42 days) divided by two (15.21 days).

Q. How are the payroll expense lags for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4. Lines 1-6 reflect the payroll expense lag. The payroll amounts shown there reflect the budgeted payroll for the future test year, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on lines 1-2 with the same bi-weekly pay period.

Q. Please discuss how the lag days associated with the purchased gas costs shown on Schedule C-4, page 2, line 4 was calculated.

A. This calculation is shown on page 6 of Schedule C-4 and is based on a review of gas purchases during the 12-month period October 2009 through September 2010. As shown there, the total dollar amount of gas purchased during that period was $74.437 million and the average payment lag equaled 38.26 days. The payment lag was determined using the midpoint of the service payment for each of the payments and the payment date for each, averaged for the entire 12-month study period.

Q. How was the Other Expense payment lag, shown on Schedule C-4, page 2, line 5, calculated?

A. The calculation of this lag is shown on page 4 to Schedule C-4. The average payment lag for all remaining expenses was derived from data for the 4 months shown in more detail on page 5 of Schedule C-4. A list of all cash disbursements during each of these months was selected in a format that would show the payee, the date service was provided or the invoice date, the amount of the disbursement, the date the payment was made by the Company, the account to which the disbursement was charged and other data associated with the disbursements. As shown on page 5, lines 1-8, each month's listing contained numerous cash disbursements. Once the raw payment data were assembled, the dollar days were determined by multiplying the amount of the disbursement by either the number for bank clearance for wire payments, or 8 days for payments made by check. Disbursements were eliminated if they were included in another calculation (e.g., gas commodity purchases), capital items, expenditures under $1,000 and over $100,000, and other non-expense amounts. After these tasks were completed, the payments shown on column 4, line 13 of Schedule C-4, page 4, were used to calculate the payment lag for general expenses of 48.91 days shown on column 5. The 48.91 day lag for Other Disbursements is then brought forward to Schedule C-4, page 2, line 5.

Q. Please explain how the interest payment amount included on line 11 of Schedule C-4, page 2 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payments of interest on outstanding debt. The pro forma annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $18,000 shown on line 5. That amount is then multiplied by the net payment lag for a reduction to the working capital allowance of $803,000, as shown on line 9. This amount is then included on page 2, line 11 of Schedule C-4.

Q. How did you determine the working capital requirement for tax payments shown on line 12 of Schedule C-4, page 2?

A. This calculation is shown on page 8 to Schedule C-4. Separate calculations are made for federal income tax, state income tax, PURTA, Property Tax and Capital Stock Tax. Each of these calculations is based on anticipated future test year tax payment and an April 1, 2011 mid-point of the service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments.

Q. How was the working capital allowance for pre-payments derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the thirteen-month average of actual pre-paid amounts for each month end from September 2009 though September 2010.

Q. What is the total amount of cash working capital claimed for CPG's rate base?

A. CPG's claim for cash working capital is $1.979 million. This amount is shown on Schedule C-4, page 2, line 14, and on Schedule A-1, columns 4-6, line 4.

4. Gas Storage Inventory

Q. Please explain how the Company determined its rate base value for its gas storage inventory.

A. As is typical for most natural gas distribution systems, CPG purchases storage gas throughout the year for use by its customers primarily during the winter heating season and to assist in balancing the various CPG gas systems. CPG's claim for gas storage inventory is also based on a 13-month historical average book value as shown on Schedule C-5.

Q. Please explain the claim for Gas Inventory shown on CPG Exhibit A (Future), Schedule C-5.

A. Gas inventory is used by the Company to supplement gas deliveries throughout the year but mostly in the winter heating months. Our claim here represents the simple average inventory derived from the thirteen-month period ending September 30, 2010 for gas stored underground. Gas stored underground represents gas volumes stored either in Company owned facilities or in storage fields owned by interstate pipelines with whom CPG contracts for capacity.

Q. Please quantify the Company's rate base claim for gas inventory.

A. The average monthly gas inventory balance for the test year if $14.344 million, as shown on Schedule C-5, line 16, column 4. This amount is also used in Schedule A-1, line 5.

Q. Please explain CPG's accounting methodology for gas in storage inventory.

A. CPG previously used a modified last-in/first-out (LIFO) methodology to price gas injected into and withdrawn from storage. This is the storage accounting mechanism that was used by the Company prior to its acquisition by UGI. Under CPG's modified LIFO method, the Company utilized an average annual inventory rate that is not finalized until the end of the fiscal year (ending September 30) after all storage gas has been purchased, injected, and/or withdrawn during the same fiscal year. This modified LIFO method required CPG initially to project the average cost of all storage gas purchases for the entire fiscal year to set an initial LIFO injection/withdrawal inventory rate. The rate derived from the total annual estimated purchase cost became the estimated inventory rate and was then updated quarterly as actual costs for purchased volumes and revised projected costs for remaining purchase volumes become available.

Consistent with other integration efforts undertaken, CPG filed a Petition with the Commission, at Docket No. P-2010-2171611, seeking approval to revise its accounting methodology for gas in storage inventory from a modified LIFO methodology to the weighted average cost of gas ("WACOG") used by both UGI and PNG. On September 23, 2010, the Commission approved CPG's request to use the WACOG methodology for gas in storage inventory.

Under the WACOG accounting methodology, the actual cost and volume of the current month's injections are added to the inventory value calculated at the end of the previous month and a new average cost per dekatherm is calculated for the current month. The current month's withdrawals are deducted from the balance at the new average cost per dekatherm. When storage gas is being injected (April through October), the inventory cost for the current month is added to the inventory cost from the previous month(s). At the end of the injection season, the storage cost for the winter is well established. During the withdrawal season (November through March), withdrawals are made at the average price primarily resulting from the injection season. Unlike the modified LIFO method, the WACOG method does not require re-pricing of prior months injections or withdrawals. As a result, the prices of monthly injections and withdrawals are more stable and certain than those under the LIFO method.

Q. Did the Commission place any conditions on the Company's use of the WACOG methodology?

A Yes. The Commission required that, until CPG's next base rate case, it must utilize WACOG as its primary accounting methodology for PGC purposes. However, CPG is also required to maintain LIFO accounting for comparison purposes and include in its next base rate case filing a full comparison of the two accounting methods with regard to both base rates and purchased gas costs.

Q. What is the difference in the rate base between the two inventory valuation methodologies?

A. Under WACOG, the 13-month average of natural gas inventory is $14.344 million and under LIFO it is $12.821 million or a difference of $1.523 million.

Q. What is the difference in Purchased Gas Costs between the two inventory valuation methodologies?

A. On December 1, CPG reduced the PGC for Rate R customers to $5.5636 per dekatherm based upon WACOG inventory pricing. Under the previous LIFO method, the PGC price would have been higher by $0.0642 per dekatherm at $5.6278 per dekatherm for a difference of $0.0642 per dekatherm.

5. Accumulated Deferred Income Taxes (ADIT)

Q. Please explain how the Company determined its rate base value for ADIT.

A. The Company's determination of its rate base value for ADIT is discussed and explained by Mr. Matthew Nolan (CPG St. No. 10.)

6. Customer Deposits/Advances for Construction

Q. Please explain how the Company determined its rate base value for customer deposits and advances for construction.

A. Customer deposits and advances for construction are customer-sourced funds that offset the need for the Company to provide capital. CPG's claims are based, again, on 13-month historical average book values as shown on Schedules C-7 and C-8.

Q. Please explain the Company's rate base claim for customer deposits shown on CPG Exhibit A (Future), Schedule C-7.

A. As reflected on Schedule C-7, the Customer Deposits rate base offset is based on a 13-month average amount of customer deposits recorded on the Company's books for the period ending September 30, 2010. The average for that period is $2.148 million as shown on line 16 of Schedule C-7 and on Schedule A-1, line 7.

Q. Please explain the Company's rate base claim for Customer Advances In Aid of Construction shown on CPG Exhibit A (Future), Schedule C-8?

A. Similar to Customer Deposits, the Customer Advances rate base offset is based on a 13-month average for the period ending September 30, 2010. The average for the period is $661 million as shown on line 16 of Schedule C-8 and on Schedule A-1, line 8.

7. Materials and Supplies Inventory

Q. Please explain how the Company determined its rate base value for materials and supplies inventory.

A. CPG maintains various materials and supplies in inventory for use in its operations. Its claim for those items is based on a 13-month historical average book value shown on Schedule C-9.

Q. What information is shown in Schedule C-9?

A. Schedule C-9 shows the Company's rate base claim for materials and supplies and undistributed stores expense. The amount claimed is $2.148 million, as shown on line 16. The amount represents the average monthly balance derived from the 13 month period ending September 2010. This value is also shown on Schedule A-1, line 9.

D. REVENUES AND EXPENSES

Q. How were the revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the change in heating degree days from that used in the budget and other pro forma adjustments. The net effect of these adjustments is shown in CPG Exhibit A (Future), Schedule D-1 and is discussed in the testimony of Mr. Szykman (CPG St. 4).

Q. Please discuss Schedule D-1 of CPG Exhibit A (Future).

A. Schedule D-1 presents a summary income statement that includes CPG's claimed gas revenues, expenses, and taxes at present and proposed rate levels. Mr. Szykman discuss the presentation of pro forma revenues and adjustments thereto and the supporting schedules in his testimony. The derivation of all pro forma expenses is set forth in the testimony of Mr. Charles F. Weekes (CPG St. no. 11.). Schedule D-1 also shows the revenue increase required of $16.460 million on line 5 in column 2.

Q. What is the level of net operating income at proposed rates?

A. As shown on column 3, line 26, $21.148 million. This represents a $9.501 million increase from the level under current rates ($11.647 million), as shown on line 26 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12 month period ending September 30, 2011. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Does the Company present schedules showing the derivation of the adjustments shown in Schedule D-2, column 3.

A. Yes. The derivation of the various column 2 revenue adjustments are included in CPG Exhibit A (Future) in summary fashion on Schedule D-3, page 1, lines 1-15, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-4. Gas Cost revenue adjustments for each customer class are shown on lines 8-11. Details for each revenue adjustment are shown in Schedules D-5A and D-5B and discussed in the testimony of Mr. Szykman. Regarding pro forma expenses, the derivation of the various adjustments are summarized individually on pages 1-2 of Schedule D-3, lines 35-48. The details for these adjustments are found in Schedules D-6 through D-35 and are discussed in the testimonies of Mr. Charles P. Weeks (CPG St. No. 11), Mr. Matthew Nolan (CPG St. No. 12), Mr. Robert F. Beard (CPG St. No. 1), Mr. David Lahoff (CPG St. No. 5) and Mr. Brian Fitzpatrick (CPG St. No. 10).

V. HISTORIC YEAR

Q. What is the purpose of the Historic Year schedules set forth in CPG Exhibit A (Historic)?

A. The historic year schedules submitted in CPG Exhibit A (Historic) are provided as a benchmark for comparison with the future test year claim. It is important to reiterate that the Company has elected to base its ratemaking claim in this case on a future test year ending September 30, 2011. The historic year measures the revenue requirement needed for the historic year ending September 30, 2010.

Q. Please describe generally the process used to prepare the pro forma schedules for the historic presentation.

A. The process is generally the same as the process used to prepare the future test year schedules. However, for each of the rate base, revenue, operating expense, and tax areas, we used the actual recorded data for the historic year ending September 30, 2010. As with the future test year, the Company reviewed the recorded data and, where appropriate, made pro forma adjustments to the recorded data. In some circumstances, I used data from the future test year schedules as the basis for several of the pro forma amounts set forth in the historic year schedules.

Q. Please describe Schedule A-1.

A. As with Schedule A-1 for the future test year, Schedule A-1 of CPG Exhibit A (Historic) summarizes the measures of value, operating expenses and revenues, and calculates rates of return at present and proposed rates.

Q. Please describe the measure of value rate base presentation on Schedule C-1.

A. Schedule C-I presents a list of the rate base items and shows no adjustments being made to the historic year ending balances for any item. The balances for several items (i.e., Gas Inventory, Customer Deposits, Customer Advances and Materials and Suppliers) are the same as those in CPG Exhibit A (Future), Schedule C-1. The amounts represent the average of the 13 months ending September 30, 2010. The rationale for these items is discussed in connection with the items in CPG Exhibit A (Future).

Q. Regarding Section D to CPG Exhibit A (Historic), please discuss Schedule D-1.

A. Schedule D-1 presents the net operating income at present and proposed rates under the Historic Year conditions. The pro forma results at present rates are shown in column 1, the revenue increase amount in column 2, and the pro forma proposed revenues under Historic Year conditions in column 3.

Q. Please explain what is shown on Schedule D-2 of CPG Exhibit A (Historic).

A. Schedule D-2 shows actual book revenues and expenses that were recorded during the year ending September 30, 2010. This schedule tracks the information shown in Schedule D-2 of CPG Exhibit A (Future), except that it is based on historic year conditions. The rationale for these items is discussed in connection with CPG Exhibit A (Future).

Q. Does Schedule D-3 of CPG Exhibit A (Historic) similarly track that of Schedule D-3 of CPG Exhibit A (Future)?

A. Yes. Schedule D-3 in both instances present a summary of the pro forma adjustments made to revenue and operating expenses, including depreciation and taxes-other than income taxes. As with the future test year, I am responsible for the rate base and expense adjustments, while Mr. Szykman discuss the revenue adjustments in his testimony (CPG St. 4). Again, the support for these items is discussed in connection with CPG Exhibit A (Historic).

Q. Does this conclude your direct testimony?

A. Yes, it does.

CPG STATEMENT NO. 3 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	
	:	Docket No. R-2010-2214415
UGI CENTRAL PENN GAS, INC.	:	

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

CPG STATEMENT NO. 3

Dated: January 14, 2010

<u>UGI Central Penn Gas Company</u>
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CPG	UGI Central Gas Inc.
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
LDC	local distribution companies
Lev	Leverage modification
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PNG	UGI Penn Natural Gas, Inc.
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor’s

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
UGIU	UGI Utilities, Inc.
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My direct testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return on common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should allow UGI Central Penn Gas, Inc. ("CPG") to realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit B, which is divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return and cost of common equity for the Company?

A. My conclusion is that CPG should be afforded an opportunity to earn a rate of return on common equity of 11.60%. As shown on Schedule 1, I have presented the 9.11% weighted average cost of capital for CPG, which is calculated with the September 30, 2011 future test year end capital structure ratios for its parent company, UGI Utilities, Inc. (“UGIU”). The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. As noted above, UGIU owns CPG and its affiliated gas utility, UGI Penn Natural Gas, Inc. ("PNG"). UGIU is itself a wholly-owned subsidiary of UGI Corporation ("UGI"). As now constituted, the natural gas distribution operations of UGIU and its subsidiaries provide service to approximately 568,000 customers in eastern and central Pennsylvania. UGIU also provides electric delivery and provider of last resort service to approximately 62,000 customers in portions of Luzerne and Wyoming Counties.

On October 1, 2008, UGIU acquired PPL Gas Utilities Corporation and renamed it CPG. At one time, CPG was known as Penn Fuel Gas, Inc. The Company provides natural gas distribution service to approximately 76,000 customers, and recently has experienced a net loss of customers. The Company's throughput is significantly influenced by sales to its heating customers. Also, a meaningful proportion of the Company's throughput is represented by transportation to commercial and industrial customers. Total transportation represents approximately 59% of total throughput. Together with some minor amount of sales, deliveries to industrial customers represent approximately 41% of total throughput. This sales profile signifies high risk for the Company. The Company obtains its natural gas from southwest and Appalachian suppliers through delivery arrangements with interstate pipelines. The Company supplements its flowing natural gas with gas withdrawn from underground storage.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as CPG. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. By considering the results of a variety of approaches, I determined that the cost of common equity is 11.50%. To the 11.50% cost of equity that I determined from the Gas Group, I have added ten basis points in recognition of the attrition in the return associated with the Company's proposed conservation program.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality. The Commission should also consider the performance of the Company's management in setting the return in this case. I have explained the basis of these ratesetting principles in Appendix B.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of seven (7) gas companies. The companies are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony. Various methods were used to determine the cost of common equity for the Gas Group.

Q. Please explain the selection process used to assemble the Gas Group?

A. I began with the all of gas utilities contained in The Value Line Investment Survey, which consists of twelve companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. Through the application of my screening process, I eliminated five companies, which were Laclede, Nicor, NiSource, Southwest Gas, and UGI Corporation. The eliminations were attributed to one of the following criteria as identified in page 2 of Schedule 3: location, operational differences, and diversification of these companies. In addition, Nicor should be removed from the group because it is the target of an acquisition by AGL Resources that is offering cash and stock that represents a 13% premium to the price of Nicor's stock prior to the announced acquisition. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company usually disconnects from its underlying fundamentals. That is to say, after it is announced, the stock trades principally on the prospect of the acquisition price that will be paid to gain control of the target company. The remaining seven companies are included in my Gas Group.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the simple arithmetic mean data for the Gas Group. The results of the models obtained from the Gas Group should reflect the risk difference between the Company and the Gas Group, including among other factors, the small size of CPG. The use of a group average (or portfolio) of utilities will reduce the effect that anomalous results for an individual company may have on the rate of return determination. That is to say, by employing variety of averaging techniques over a portfolio, rather than individual company analyses, will reduce the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, reliance on a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	9.94%
RP	11.25%
CAPM	11.36%
Comparable Earnings	13.45%
Measures of Central Tendency:	
Average	11.50%
Median	11.31%
Mid-point	11.70%

The average of all methods shown above is 11.50%. My recommended rate of return on common equity of 11.60% and is comprised of the 11.50% average of all methods plus 0.10% for the attrition in return that the Company is expected to experience with the implementation of its proposed conservation program. As explained in the testimony of Mr. Beard, if the Company's proposed conservation program is successful, it will produce a reduction of approximately $200,000 of annual revenues, which equates to a reduction in the rate of return on common equity of ten (10) basis points. The Company should not be penalized for undertaking this program in response to conservation initiatives proposed in response to public policy directives. My proposed rate of return on common equity makes no provision for the prospect that it may not be achieved due to unforeseen events, such as unexpected spikes in the cost of purchased products and other expenses. The Company's rate of return on common equity should also reflect the superior performance of its management as described is the testimony of Mr. Beard. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Indeed, in a study dated December 9, 2008, prepared for the American Gas Foundation, it was noted that allowed equity returns below the level required by investors may lessen a utility's ability to maintain and develop systems that are necessary to provide natural gas service efficiently. Furthermore, the report specifically found that returns below 10% would trigger broad disenchantment with LDC investment.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for large volume customers. Of particular concern for the Company is its stagnant, if not declining, customer base, as described in the testimony of Messrs. Beard and Szykman. These witnesses also explain the impact of the current economic situation on throughput to large volume users. Also, the existence of locally produced gas provides a bypass threat to the Company. This situation will only become more intense with further development of production from the Marcellus Shale formation. The availability of additional supplies of natural gas from the Marcellus Shale formation will provide a number of the Company's large volume customers with the opportunity to obtain their supply directly from producers, thereby increasing the Company's risk related to the bypass of its system.

In addition, natural gas utilities have focused increased attention on safety and reliability issues. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues.

Q. How does the Company's throughput to industrial and transportation customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial and transportation customers engaged in building materials, metals and chemicals as discussed by Mr. Beard. The Company's service territory is crossed by four interstate pipelines. Large volume users in close proximity to these pipelines have the ability to bypass the Company's system. As noted by Mr. Beard, seven of the Company's customers are capable of physical bypass.

Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on its operations from facilities located outside the Company's service territory.

Q. Are there other specific features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Several factors have a negative impact on the Company's operations, thereby increasing its risk profile. As I will discuss below, the Company is a small gas distribution utility that serves principally a rural territory. In its rural territory, the Company experiences competition from propane for space heating and other energy needs. The rural nature of its service territory also makes the cost of adding new customers relatively high. Approximately 94% of the Company's residential customers use natural gas for space heating purposes. This indicates that a significant proportion of the Company's residential customers present a low load factor profile and that its energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. For these sales, the Company's revenues are subject to variations caused by weather abnormalities.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is required to undertake investments to maintain and upgrade existing facilities in its service territories. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. Along those lines, the rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. CPG had 641 miles of its distribution mains constructed of cast iron and unprotected steel pipe as of year-end 2009. The Company projects its construction expenditures will be approximately $51.6 million during the period 2011-2014. The Company's total capital expenditures over the next four years will represent approximately 22% ($51.6 million ÷ $234.1 million) of its net utility plant in service at September 30, 2010. As previously noted, a fair rate of return represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its needs on reasonable terms.

Q. How should the Commission respond to the issues facing the natural gas utilities and, in particular, the Company?

A. The Commission should recognize and take into account the heightened competitive environment and the risk it poses in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to risk related to earnings attrition and regulatory lag since its costs are rising each year. Indeed, the Company is proposing an aggressive conservation program in this case, which will negatively impact its revenue and earnings, unless a separate provision is made to deal with lost margins. I have proposed adjusting the rate of return on common equity upward by 10 basis points to compensate the Company for the lost margins related to this program.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I compared CPG to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for CPG, the Gas Group, and the S&P Public Utilities?

A. The long-term debt of UGIU carries an A3 rating from Moody's Investors Service. Presently, the average corporate credit rating ("CCR") for the Gas Group is A from Standard & Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is A3 from Moody's. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for CPG, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2005-2009. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, CPG is very much smaller than the average size of the Gas Group. The average size of the S&P Public Utilities is much larger than the Gas Group, and the Gas Group is much larger than CPG. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for CPG and the Gas Group.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings and hence; a lower price-earnings ratio.[1]

There are no market ratios available for CPG because the Company's stock

[1]For example, two otherwise similarly situated firms each reporting $1.00 earnings per share would have different market prices at varying levels of risk, i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value.

is not traded. The five-year average price-earnings multiple was somewhat higher for the Gas Group as compared to the S&P Public Utilities. In 2009, the price-earnings multiple increased significantly for the Gas Group. The five-year average dividend yield was fairly similar for the Gas Group and the S&P Public Utilities. The five-year average market-to-book ratio was fairly similar for the Gas Group and the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 54.4% for the Gas Group and 45.8% for the S&P Public Utilities. The capital structure ratios are not meaningful for CPG because all of its debt has been redeemed following its acquisition by UGIU.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.500 (1.8% ÷ 3.6%) for CPG, 0.085 (1.0% ÷ 11.8%) for the Gas Group, and 0.103 (1.2% ÷ 11.7%) for the S&P Public Utilities. The earnings variability for CPG was much higher than the Gas Group, and hence the Company's risk is greater.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income taxes). The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin. The five-year average operating ratios were 91.2% for CPG, 88.8% for the Gas Group, and 84.4% for the S&P Public Utilities. The operating risk for CPG is higher than that of the Gas Group.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 4.33 times for the Gas Group and 3.42 times for the S&P Public Utilities. Coverage calculations for CPG are not meaningful because all of the Company's debt has been redeemed.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for CPG, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 96.3% for the Gas Group and 88.4% for the S&P Public Utilities. Historical cash flow statements are not available for CPG so the IGF to construction has not been calculated.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[2] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .66 as the average for the Gas Group (see page 2 of Schedule 3), and .77 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation of the Company and the Gas Group.

A. The risk of CPG is greater than that of the Gas Group. The Company's small size and rural service territory adds to its risk, it faces the threat of bypass from the interstate pipelines, including the developing impact of additional gas supplies available from the Marcellus Shale formation, it has a high percentage of throughput to industrial customers, its earnings have been highly variable, and its operating ratio is high. As such, the cost of equity derived from the Gas Group provides a conservative basis to measure the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for the Company.

A. In this case, the capital structure ratios of UGIU have been proposed to calculate the rate of return. Usually, where the operating public utility raises its own debt, it is proper to employ the capital structure ratios and senior capital cost rates of the

[2] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix H. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

regulated public utility for rate of return purposes. UGIU provides all capital to each of its subsidiaries, and as such CPG has no debt in its capital structure. Furthermore, consistency requires that the embedded cost of UGIU's senior securities should also be employed.

Q. Does Schedule 5 provide the capitalization and capital structure ratios of UGIU?

A. Yes. Schedule 5 presents the capitalization and related capital structure ratios of UGIU at September 30, 2010. This schedule also provides the September 30, 2011 capital structure estimated at the end of the future year. A forecast increase in retained earnings by September 30, 2011 has been reflected, which represents the only major change in the capital structure in the future test year. In presenting the capital structure of UGIU on Schedule 5, I have made several adjustments for ratesetting purposes. Those adjustments include (i) the call premiums on the early redemption of high cost long-term debt, which has been redeemed, and (ii) accumulated other comprehensive income ("OCI").

Q. Please describe the first adjustment.

A. I have adjusted the principal amount of long-term debt to remove the amounts used to finance the call premiums paid on the early redemption of these securities. To do otherwise would deny UGIU the full return on the premiums paid to redeem this high cost capital since additional amounts of capital were incurred by the Company to pay the call premiums to investors. An adjustment is required to the principal amount of long-term debt in order to provide the return necessary to service this additional capital.

This adjustment is equitable because customers receive the cost savings resulting from these refinancings in the form of a lower overall rate of return, and

UGIU recovers all costs incurred in providing these benefits to customers. To produce these savings, UGIU paid the debt holders a premium for surrendering its securities prior to maturity. These premiums represented an investment made by UGIU to reduce its overall cost of capital. Because the reduced interest costs are reflected in the lower cost of capital to customers, it is appropriate that UGIU recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium as a part of the cost of capital, and has been accepted in many rate case decisions by the Commission.

Q. Please describe the second adjustment.

A. I also have removed the accumulated OCI from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability, foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. For UGIU, most of the OCI is represented by accounting entries associated with SFAS No. 158, which relates to pensions and OPEBs, and to changes in the value of derivative instruments. For UGIU, its OCI also contains the unrealized gains and losses on the Interest Rate Protection Agreement (“IRPA”) related to various debt issuances.

Q. Should short-term debt be included in the capital structure for rate of return purposes?

A. Perhaps, but only after a thorough analysis. Short-term debt serves several purposes for a public utility. Principally, it provides bridge financing for construction work in progress, until the magnitude of short-term debt reaches a point where a permanent financing with long-term debt and equity is economic. That is to say, short-term debt is temporary financing pending the issuance of long-term debt and equity in the desired proportions that support the Company's capital structure goals. For natural gas utilities, short-term debt is also used to meet seasonal working capital needs related to stored gas inventory that accumulates during the summer and early fall prior to the send out to customers in the heating session. Short-term debt then declines after customers pay for the gas sold to them. The cycle then repeats. Another use of short-term debt by some natural gas utilities relates to the temporary financing of regulatory assets, such as under-recovered purchased gas costs, deferred environmental remediation costs, and other costs incurred but not yet paid by customers. The bottom line is that short-term debt should be included in the capital structure for rate of return purposes only after a detailed analysis.

Q. Does Schedule 5 include a provision for short-term debt?

A. Yes. I have included the average balance of short-term debt in the capital structure for the historic and future test year. The significant decline in the average balance during the future test year can be traced to the lower commodity cost of gas in underground storage.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the test year. As a result, I will adopt the Company's future test year-end capital structure ratios of 46.44% (45.03% long-term and 1.41% short-term) debt and 53.56% common equity. I have verified the reasonableness of these ratios by considering analysts' forecasts, which influence investor expectations. I have compared the Company's proposed common equity ratio of UGIU to that of the Gas Group based upon data widely available to investors from Value Line. In the case of the Value Line forecasts, the common equity ratios are computed without regard to short-term debt. Those ratios are:

Company	2010	2011	2013-15
AGL Resources, Inc.	55.0%	56.0%	61.0%
Atmos Energy Corporation	55.0%	53.0%	51.0%
New Jersey Resources Corp.	58.5%	58.5%	60.0%
Northwest Natural Gas Co.	54.0%	55.0%	60.0%
Piedmont Natural Gas Company	55.0%	54.5%	52.5%
South Jersey Industries, Inc.	59.0%	59.0%	61.5%
WGL Holdings, Inc.	62.5%	63.5%	64.5%
Average	57.0%	57.1%	58.6%

Source: The Value Line Investment Survey, September 10, 2010

These forecasts show that the capital structure ratio for this case contains somewhat more financial risk, i.e., the common equity ratio is lower than the Gas Group. Here, the future test year common equity ratio for UGIU is 54.33% computed by excluding to short-term debt, as compared to the 57.1% common equity ratio of the Gas Group also computed without regard to short-term debt.

COSTS OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of UGIU's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that UGIU has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2010. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2011. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 3 of Schedule 6. The cost rate, or yield to maturity ("ytm"), is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond. In my calculation of the embedded cost of long-term debt, I have recognized the cost/benefit associated with the IRPAs used for various issues of debt. For various issues of long-term debt noted on page 3 of Schedule 6, UGIU established IRPAs as a means to hedge its exposure to changes in interest rates prior to the issuance of long-term debt. As previously explained, I also reflected the adjustment associated with UGIU's early redemption of high cost debt in order to compensate for the costs incurred to lower the embedded debt cost rate, which reduces the cost of capital charged to customers.

Q. What cost rate have you determined for the Company's long-term debt?

A. I will adopt the 6.37% embedded cost of long-term debt at September 30, 2011, as shown on page 2 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 44.16% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. For the future test year, I have used a cost of short-term debt of 2.38%. The Company is planning to establish a new Revolving Credit Agreement that will carry a borrowing rate of LIBOR plus a margin of 125 to 150 basis points. The 2.38% cost of short-term debt for the future test year is based on the first quarter 2012 forecast of 1.0% for LIBOR based on the <u>Blue Chip Financial Forecast</u> dated December 1, 2010. To this rate, I have added the midpoint of the expected margin. The other costs associated with the new Revolving Credit Agreement, including upfront fees, the arrangement fees, and the undrawn fees are reflected in the Company's cost of service as an A&G expenses.

Q. What overall debt cost rate have you determined for rate of return purposes?

A. As shown on page 2 of Schedule 6, the combined cost of long- and short-term debt is 6.24% for the future test year.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for CPG.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPG, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.50% for CPG, which also includes 10 basis points for the lost margins associated with the Company's proposed conservation program.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process where, as in this case, the firm's market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended October 2010, the monthly dividend yields of the Gas Group are shown graphically on Schedule 7. The monthly dividend yields shown on Schedule 7 reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix E.

For the twelve months ended October 2010, the average dividend yield was 4.08% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 4.01% and 3.89%, respectively. I have used, for the purpose of my direct testimony, the six-month average dividend yield of 4.01% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix E. That adjusted dividend yield is 4.13% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). As I explain in Appendix E, future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis also can be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the proxy group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedule 8 and 9. The bar graph provided on Schedule 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical growth of earnings per share was in the range of 6.71% to 7.50% for the Gas Group.

Schedule 9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar, and Value Line. IBES/First Call, Zacks, and Morningstar represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Morningstar forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, current market performance is strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage and, indeed, they dominate these publications.

Q. Is a five-year investment horizon associated with the analysts' forecasts

consistent with the DCF model?

A. Yes. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor-expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, is consistent with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 4.19% by IBES/First Call, 4.51% by Zacks, 5.61% by Morningstar, and 4.71% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 4.71%) than the dividends per share (i.e., 3.57%), which translates into a declining dividend payout ratio for the future. As noted earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts. Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investor expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments, and are the primary driver of retention growth and its surrogate, i.e.

book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[3] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, represent a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Morningstar, and Value Line. The IBES/First Call, Zacks, and Morningstar growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Morningstar estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of growth rates of 4.19% to 5.61%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts. The Value Line forecast of

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

dividend per share growth is inadequate in this regard due to the forecasted decline in the dividend payout ratio. Moreover, the restructuring and consolidation now taking place in the utility industry will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts, and will enhance the growth prospects for the future. In my opinion, a 5.25% growth rate will accommodate all these factors.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q. Please explain why.

A. If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital based on a book value capital structure used for ratesetting purposes, the utility will not, by definition, recover its risk-adjusted capital cost. This is because market valuations of equity are based on market value capital structures, which in general have more equity and less debt and therefore reflect less risk than book value capital structures. The utility's risk-adjusted cost of equity will necessarily be lower with the market value capital structure than it is relative to the book value capital structure. The difference represents that portion of the utility's cost of equity that it will not recover unless either the market value cost of equity is applied to the utility's market value capital structure or it is adjusted to reflect the higher risk associated with the book value capital structure. By the same token, if the utility's market value capital structure is less than its book value structure, then the utility's market cost of equity should be adjusted downward to reflect the lower risk associated with the book value capital structure.

This shortcoming of the DCF has persuaded the Commission to adjust the DCF determined cost of equity upward to make the return consistent with the book value capital structure. Specific adjustments to recognize this risk difference were made in the following cases:

- January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-00016339 -- 60 basis points adjustment.
- August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750 -- 80 basis points adjustment.
- January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis points adjustment.
- August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis points adjustment.
- December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-00049255 -- 45 basis points adjustment.
- February 8, 2007 for PPL Gas Utilities Corporation (now UGI Central Penn Gas, Inc.) in Docket No. R-00061398 -- 70 basis points adjustment.

In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification.

Q. Is your leverage adjustment dependent upon the market valuation or book valuation from an investor's perspective?

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. Multiple terms are used in the case of debt and preferred stock.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations regarding market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from its cost of equity. Stock prices above book value are common for utility stocks and, indeed, the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of November 1, 2010, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.57 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 2.85 times book value, and the Dow Jones Industrial index was at 2.68 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of its cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse also is true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases.[4] This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. Simply stated, the leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. There can be no dispute that a firm’s financial risk varies with the relative amount of leverage

[4] Modigliani, F. and Miller, M.H. “The Cost of Capital, Corporation Finance, and the Theory of Investments.” American Economic Review, June 1958, 261-297.

Modigliani, F. and Miller, M. H. “Taxes and the Cost of Capital: A Correction.” American Economic Review, June 1963, 433-443.

contained in its capital structure. As detailed in Appendix E, the Modigliani and Miller theory when applied to the Gas Group shows that the cost of equity increases by 0.56% (9.94% - 9.38%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. This is because the equity return applicable to the book value common equity ratio is equal to 8.34%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 1.59% compensation for having a 43.81% debt ratio, plus 0.01% for having a 0.24% preferred stock ratio (see pages E-12 and E-13 of Appendix E). The sum of the parts is 9.94% (8.34% + 1.59% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 4.13% dividend yield, the 5.25% growth rate, and the 0.56% for the leverage adjustment in order to arrive at the same 9.94% (4.13% + 5.25% + 0.56%) return. I know of no means to mathematically solve for the 0.56% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.56% adjustment is merely a convenient way to compare the 9.94% return computed directly with the Modigliani & Miller formulas to the 9.38% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1 /P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g ") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	*lev.*	=	k
Gas Group	4.13%	+	5.25%	+	0.56%	=	9.94%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity, especially in light of the Company's risk profile, its management performance, and the effects of the proposed conservation program.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 5.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. The Moody's index and the Blue

Chip forecasts support this figure. The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 10. For the twelve months ended October 2010, the average monthly yield on Moody's A-rated index of public utility bonds was 5.51%. For the six and three-month periods ended October 2010, the yields were 5.22% and 5.04%, respectively. During the twelve-months ended October 2010, the range of the yields on A-rated public utility bonds was 5.01% to 5.87%.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix F. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2010, and a yield spread of 1.50%. As shown on page 5 of Schedule 10, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.42% on a twelve-month average basis, 1.50% on a six-month average basis, and 1.54% on a the three-month average basis. From these averages, 1.50% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2010	Fourth	4.6%	5.6%	3.8%	1.50%	5.30%
2011	First	4.6%	5.6%	3.8%	1.50%	5.30%
2011	Second	4.7%	5.7%	3.9%	1.50%	5.40%
2011	Third	4.9%	5.9%	4.1%	1.50%	5.60%
2011	Fourth	5.0%	6.0%	4.3%	1.50%	5.80%
2012	First	5.2%	6.2%	4.5%	1.50%	6.00%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2010 publication, the Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2012-16	6.0%	7.0%	5.3%
2017-21	6.3%	7.2%	5.6%

Given these forecasted interest rates, a 5.75% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities, rather than some broader market indexes, such as the S&P 500 Composite index. The S&P

Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 11, the indicated risk premiums for the various time periods analyzed are 5.51% (1928-2007), 6.58% (1952-2007), 6.08% (1974-2007), and 6.37% (1979-2007). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals, and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 11 represents the returns realized through 2007. An update to 2008 has not been prepared because of the difficulty in obtaining the return on public utility bonds from Lehman Brothers, which is in bankruptcy. Second, the selection of the initial year of each period was based upon the financial market defining events that I note here and describe in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the

Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. I consistently use these periods in my work, and additional data are merely added to the earlier results when they become available. The periods chosen are, therefore, not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 11, the 1928-2007 period provides the lowest indicated risk premium, while the 1952-2007 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 6.23% (6.08% + 6.37% = 12.45% ÷ 2) is derived by averaging data covering the periods 1974-2007 and 1979-2007. Therefore, 6.23% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.50% represents a reasonable common equity risk premium in this case. This represents approximately 88% (5.50% ÷ 6.23% = 0.88) of the risk premium of the S&P Public Utilities, and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Gas Group	5.75%	+	5.50%	=	11.25%

CAPITAL ASSET PRICING MODEL

Q. Have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. Yes. As with other models of the cost of equity, the CAPM contains a variety of assumptions and shortcomings that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will help reduce the unavoidable defects found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM, it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors, because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity, because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 12, the average beta is 0.66 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[5] as follows:

[5] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and, therefore, are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.50 for the Gas Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of 0.76 for the book value capital structure of the Gas Group. The betas and corresponding common equity ratios are:

Market Values		Book Values	
Beta	Common Equity Ratio	Beta	Common Equity Ratio
0.66	66.16%	0.76	55.95%

The book value leveraged beta that I will employ in the CAPM cost of equity is 0.76 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. For the reasons explained in Appendix F, I have employed the yields on 20-year Treasury bonds using historical data. For forecasts, I have used the yields on 30-year Treasury bonds that are published by Blue Chip. The reason that I used the 20-year Treasury yield in my historical analysis relates to the interruption in the 30-year series, which had no data reported for the months of March 2002 to January 2006. That is to say, 48-months of data were missing from the 60-months that I used for my five-year historical analysis shown on page 2 of Schedule 12. As

Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452 shown on pages 2 and 3 of Schedule 12, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2010, the average yield was 4.08%, as shown on page 3 of that schedule. For the six- and three-months ended October 2010, the yields on 20-year Treasury bonds were 3.73% and 3.50%, respectively. During the twelve-months ended October 2010, the range of the yields on 20-year Treasury bonds was 3.47% to 4.53%. In recent months, there has been a significant decline in the yields on Treasury obligations, which can be traced to a number of factors, including: a purported bubble that may be developing in the market for Treasury obligations, the sovereign debt crisis, concern over a possible double dip recession, the possibility of potential deflation, and maintenance by the Fed of its large balance sheet through the reinvestment of the proceeds from maturing mortgage-backed securities with the purchase of Treasury obligations. While Treasury yields have declined for a variety of reasons, the decline in corporate (i.e., public utility) bond yields has not been so pronounced or revealed by the increased spreads, that I discussed previously. As shown on page 4 of Schedule 12, forecasts published by Blue Chip November 1, 2010 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.8% to 4.5% during the next six quarters. The longer term forecasts described previously (see Blue Chip Financial Forecast presented earlier) show that the yields on 30-year Treasury bonds will average 5.3% from 2012 through 2016 and 5.6% from 2017 to 2021. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 4.25% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

Q. What market premium have you used in the CAPM?

A. As shown in Appendix H, the market premium is derived from the SBBI Classic Yearbook (i.e., 6.35%) and the Value Line and S&P 500 returns (i.e., 9.50%). For the historically based market premium, I have used the arithmetic mean. The market premium as averaged from these sources equals 7.93% (6.35% + 9.50% = 15.85% ÷ 2).

Q. Are there adjustments to the CAPM results that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $1,806 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.08%.

Q. What CAPM result have you determined?

A. Using the 4.25% risk-free rate of return, the leverage adjusted beta of 0.76 for the Gas Group, the 7.93% market premium, and the 1.08% size adjustment, I derived the following CAPM-indicated cost of equity:

	Rf	+	*ß*	*x* (	*Rm-Rf*	) +	*size*	=	*k*
Gas Group	4.25%	+	0.76	x (	7.93%	) +	1.08%	=	11.36%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of the Comparable Earnings approach are set forth in Appendix I. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties…. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 13, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and to the extent that investors rely on the Value Line service to gauge returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 13.2% using only the returns that were less than 20% as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.7% also using values less than 20%, as provided on page 2 of Schedule 13.

Q. What rate of return on common equity have you determined in this case

using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

		Historical		*Forecast*		*Average*
Comparable Earnings Group		13.2%		13.7%		13.45%

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of the variety of methods and models described previously, I recommend that the Commission set the Company's rate of return on common equity at 11.60%. The rate of return on common equity that the Commission adopts should reflect the Company's higher risk profile as compared to the Gas Group, the performance of its management, and the impact of the Company's proposed conservation program. My cost of equity recommendation should be considered in the context of the Company's high risk characteristics. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. My cost of equity recommendation makes no provision for the prospect that the rate of return may not be achieved due to regulatory lag, attrition and/or other unforeseen events.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

CPG EXHIBIT NOS. – PRM APPENDICES A THROUGH I

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	
	:	Docket No. R-2010-2214415
UGI CENTRAL PENN GAS, INC.	:	

Appendices A through I to Accompany

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

CPG STATEMENT NO. 3

Dated: January 14, 2010

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-six (36) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-

0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October

1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2006	Thirty-eighth Financial Forum	Society of Utility & Regulatory Financial Analysts
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility

		Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

Traditional cost of service regulation, as implemented by a regulatory agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide the public utility and its investors with an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with customers has been changing, a regulated utility remains quite different from a non-regulated firm, which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests have been articulated through which the regulator can determine the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to satisfy its capital requirements so that it can meet the obligation to

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms, which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings, which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk, which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation, which lacks such a basis, will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods, which have been employed to measure the cost of equity, include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns, which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns, which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the landmark decisions on the issue of rate of return. These decisions require that a fair return for a utility must be equal to that earned by firms of comparable risk.

APPENDIX E TO DIRECT TESTIMONY OF PAUL R. MOUL

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = \$100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate, which reflects the risk or uncertainty, associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If *P* represents price, *Kp* is the required rate of return on a preferred stock, and *D* is the annual dividend (*P* and *D* with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, *Kp*. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0\,(1 + g)}{Ks - g}$$

generic form of the DCF. If, however, it is assumed that D_1, D_2, D_3, $\ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0\,(1 + g) = D_1$, $D_1\,(1 + g) = D_2$, $D_2\,(1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0\,(1 + g)}{P_0} + g$$

[1]Although the popular application of the DCF model is often attributed to the work of Myron J.

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of $0.80, the current price (P_0) of $10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be $17.10 as compared with the price per share of $16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price (P_0) of $10.00, a dividend (D_0) of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Schedule 3. The 2005-2009 five-year average dividend yield was 3.9% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 7. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as $\boldsymbol{D_0}$, may be stated in this fashion:

$$K = \frac{D_0\,(1+g)^{0} + D_0\,(1+g)^{0} + D_0\,(1+g)^{1} + D_0\,(1+g)^{1}}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.625% (5.25% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.12% (4.01% x 1.02625) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as follows:

$$K = \frac{D_0\,(1+g)^{.25} + D_0\,(1+g)^{.50} + D_0\,(1+g)^{.75} + D_0\,(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.14% (4.01% x 1.03260) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^{4} - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *(D_0)*:

$$k = \left[\left(1 + \frac{D_0 \, (1+g)^{.25}}{P_0} \right)^4 - 1 \right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 1.0025% (4.01% ÷ 4) for the Gas Group. The compound dividend yield would be 4.12% (1.010154^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 4.13% forward-looking dividend yield is the average (4.12% + 4.14% + 4.12% = 12.38% ÷ 3) of the adjusted dividend yield using the form $D_0 / P_0 \, (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research. As with the IBES/First Call forecasts, Zacks provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focuses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior

[2]As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*B*x*R*" shown on Schedule 9. Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments"

(Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

Gas Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	33.66%	43.81%
Preferred Stock	0.17	0.24
Common Equity	66.16	55.95
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D\ /\ E) - (ku - d)\ P\ /\ E$$

$$8.34\% = 9.38\% - (((8.34\%-5.22\%)\ .65)\ 33.66\%/66.16\%) - (8.34\% - 6.04\%)\ 0.17\%/66.16\%$$

where *ku* = cost of equity for an all-equity firm, *ke* = market determined cost equity, *i* = cost of debt[3], *d* = dividend rate on preferred stock[4], *D* = debt ratio, *P* = preferred stock ratio, and *E* = common equity ratio. The formula shown above indicates that the cost of equity for a firm with

[3] The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

[4] The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

100% equity is 8.34% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 8.34% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$9.94\% = 8.34\% + (((8.34\%-5.22\%).65)\ 43.81\%/55.95\%) + (8.34\%-6.04\%)\ 0.24\%/55.95\%.$$

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation that is reflected in current interest rates may be quite different from the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve, which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes, which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions, which impact directly short-term interest rates also substantially, affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system, which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board (“FOMC”) began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend, which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0%, which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market, which provides ease of trading, and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds, which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70% on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as “a rapid and forceful response of monetary policy” to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future.

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate.

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future.

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time.

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) concerns regarding the Federal budget deficit. All these factors significantly changed the sentiment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate.

Just after the FOMC meeting on August 7, 2007, where the FOMC decided to retain a 5.25% Fed Funds rate, turmoil in the credit markets prompted central banks throughout the world to inject over $325 billion of reserves into the banking system over a three-day period in reaction to a credit crunch. Problems had been developing earlier in 2007, beginning in the market for asset-backed securities linked to subprime mortgages. Valuation uncertainties for these securities caused liquidity concerns for hedge funds, investment banks, and financial institutions. The market for commercial paper, the most liquid part of the credit markets for non-Treasury securities, was also affected. In response to the market turmoil, the FOMC issued the following statement, the first of its type since after the September 11, 2001 terrorists' attack.

> The Federal Reserve is providing liquidity to facilitate the orderly functioning of financial markets.

> The Federal Reserve will provide reserves as necessary through open market operations to promote trading in the federal funds market at rates close to the Federal Open Market Committee's target rate of 5-1/4 percent. In current circumstances, depository institutions may experience unusual funding needs because of dislocations in money and credit markets. As always, the discount window is available as a source of funding.

Then, one week after its initial announcement, the FOMC made a surprise reduction of 50 basis points in the discount rate to narrow the spread between this rate and the target Fed Funds rate. At the same time, the FOMC made the following statement:

> Financial market conditions have deteriorated, and tighter credit conditions and increased uncertainty have the potential to restrain economic growth going forward. In these circumstances, although recent data suggest that the economy has continued to expand at a moderate pace, the Federal Open Market Committee judges that the downside risks to growth have increased appreciably. The Committee is monitoring the situation and is prepared to act as needed to mitigate the adverse effects on the economy arising from the disruptions in financial markets.

Thereafter, at its regularly scheduled meeting on September 18, 2007, the FOMC reduced the target Fed Funds rate to 4.75% and the discount rate was reduced to 5.25% in an effort to forestall the adverse effects of the financial market turmoil on the economy generally. Further reductions of 25 basis points occurred at the next two FOMC meetings on October 31, 2007 and on December 11, 2007. The December 11, 2007 FOMC statement indicated that:

> Incoming information suggests that economic growth is slowing, reflecting the intensification of the housing correction and some softening in business and consumer spending. Moreover, strains in financial markets have increased in recent weeks. Today’s action, combined with the policy actions taken earlier, should help promote moderate growth over time.
>
> Readings on core inflation have improved modestly this year, but elevated energy and commodity prices, among other factors, may put upward pressure on inflation. In this context, the Committee judges that some inflation risks

> remain, and it will continue to monitor inflation developments carefully.
>
> Recent developments, including the deterioration in financial market conditions, have increased the uncertainty surrounding the outlook for economic growth and inflation. The Committee will continue to assess the effects of financial and other developments on economic prospects and will act as needed to foster price stability and sustainable economic growth.

With these actions, the Fed Funds rate and the discount rate closed the calendar year 2007 at 4.25% and 4.75%, respectively.

During 2008, many critical events occurred that influenced the capital markets, and hence interest rates. They include: (i) the collapse of The Bear Stearns Company and its acquisition by JPMorgan Chase & Co. with the aid of the Federal Reserve Bank of New York announced on March 16, 2008; (ii) the failure of IndyMac on July 11, 2008, which was at the time the third-largest banking failure in U.S. history, after a “run on the bank” by depositors; (iii) the placement of the government-sponsored enterprises (“GSE”) Federal National Mortgage Association (Fannie Mae) and Freddie Mac into conservatorship on September 7, 2008 by the Federal Housing Finance Agency; (iv) the largest bankruptcy filing in history by Lehman Brothers Holding, Inc. on September 15, 2008; (v) the acquisition of the banking operations of Washington Mutual, then the largest U.S. savings bank, by JPMorgan Chase on September 24, 2008, (Washington Mutual’s holding company subsequently filed for bankruptcy protection); (vi) the rescue of Merrill Lynch & Co., Inc. by Bank of America on September 15, 2008, with assistance of the Federal government; (vii) the effective nationalization on September 23, 2008, of American International Group, then the world’s largest insurance company, through the acquisition of 79.9% of its equity by the U.S. Treasury and (viii) other significant events affecting financial markets globally. The FOMC acted decisively in response to the events described above. Acting prior to its first regularly scheduled meeting in 2008, on

January 22, 2008, the FOMC reduced the fed funds target by 75 basis points to 3.50% and the discount rate was reduced by a corresponding amount to 4.00%. Actions by the FOMC between meetings are unusual occurrences in recent years, thereby signifying the urgency that the FOMC saw in taking immediate action on monetary policy in response to the financial crisis. Then on January 30, 2008, the fed funds target rate and discount rate were further reduced by 50 basis points, bringing those rates to 3.00% and 3.50%, respectively. Credit market turmoil continued, and after the collapse of The Bear Stearn Companies noted above, the FOMC stated:

> The Federal Reserve on Sunday announced two initiatives designed to bolster market liquidity and promote orderly market functioning. Liquid, well-functioning markets are essential for the promotion of economic growth.
>
> First, the Federal Reserve Board voted unanimously to authorize the Federal Reserve Bank of New York to create a lending facility to improve the ability of primary dealers to provide financing to participants in securitization markets. This facility will be available for business on Monday, March 17. It will be in place for at least six months and may be extended as conditions warrant. Credit extended to primary dealers under this facility may be collateralized by a broad range of investment-grade debt securities. The interest rate charged on such credit will be the same as the primary credit rate, or discount rate, at the Federal Reserve Bank of New York.
>
> Second, the Federal Reserve Board unanimously approved a request by the Federal Reserve Bank of New York to decrease the primary credit rate from 3-1/2 percent to 3-1/4 percent, effective immediately. This step lowers the spread of the primary credit rate over the Federal Open Market Committee's target federal funds rate to 1/4 percentage point. The Board also approved an increase in the maximum maturity of primary credit loans to 90 days from 30 days.
>
> The Board also approved the financing arrangement announced by JPMorgan Chase & Co. and The Bear Stearns Companies Inc.

Then on March 18, 2008, the FOMC reduced the fed funds rate to 2.25% and the discount rate to 2.50%. Afterward on April 30, 2008, the FOMC further reduces the fed funds rate to 2.00% and the discount rate to 2.25%. At subsequent meetings the FOMC held the fed funds rate steady. Then on October 8, 2008, the FOMC took another unusual unscheduled action by reducing the Fed Funds rate to 1.50% and the discount rate to 1.75%. Then, on October 29, the FOMC lowered the Fed Funds rate to 1.00% and the discount rate to 1.25%. As 2008 ended, the FOMC lowered the Fed Funds rate to a target range of 0.00% to 0.25%, its lowest rate ever. As a further response to the financial crisis, Congress passed and the President signed on October 3, 2008, the Emergency Economic Stabilization Act of 2008, which, among other provisions, provides the mechanism to deploy up to $700 billion through the Troubled Asset Relief Program ("TARP") to address urgent needs created by the credit crisis the country has experienced. Then, the Federal Reserve Board instituted its Commercial Paper Funding Facility ("CPFF"), which was authorized on October 7, 2008, and it participated in coordinated efforts by major central banks to support financial stability and to maintain flows of credit in the banking system. These programs included a $75 billion Term Auction Facility ("TAF"), a future TAF auction totaling $150 billion, and an increase to $620 billion of swap authorizations with central banks in Canada, England, Japan, Denmark, the European Union, Norway, Australia, Sweden, and Switzerland. Further, on February 17, 2009, the President signed the American Recovery and Reinvestment Act that committed $789 billion by the Federal government in an effort to create jobs, jumpstart growth and to transform the economy in reaction to the recession that began in December 2007.

The FOMC maintained its target range of 0.00% to 0.25% throughout the remainder of 2009 and 2010. At its November 3, 2010 meeting, the FOMC stated:

> Information received since the Federal Open Market Committee met in September confirms that the pace of recovery in output and employment continues to be slow.

> Household spending is increasing gradually, but remains constrained by high unemployment, modest income growth, lower housing wealth, and tight credit. Business spending on equipment and software is rising, though less rapidly than earlier in the year, while investment in nonresidential structures continues to be weak. Employers remain reluctant to add to payrolls. Housing starts continue to be depressed. Longer-term inflation expectations have remained stable, but measures of underlying inflation have trended lower in recent quarters.
>
> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Currently, the unemployment rate is elevated, and measures of underlying inflation are somewhat low, relative to levels that the Committee judges to be consistent, over the longer run, with its dual mandate. Although the Committee anticipates a gradual return to higher levels of resource utilization in a context of price stability, progress toward its objectives has been disappointingly slow.
>
> To promote a stronger pace of economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate, the Committee decided today to expand its holdings of securities. The Committee will maintain its existing policy of reinvesting principal payments from its securities holdings. In addition, the Committee intends to purchase a further $600 billion of longer-term Treasury securities by the end of the second quarter of 2011, a pace of about $75 billion per month. The Committee will regularly review the pace of its securities purchases and the overall size of the asset-purchase program in light of incoming information and will adjust the program as needed to best foster maximum employment and price stability.

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim, which lenders have on the earnings, and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 10 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds, which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 10. There, it is shown that those spreads were about one percent during the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to the run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 10, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds was about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005, 1.08% in 2006, 1.16% in 2007, 2.17% in 2008, and 1.93% in 2009. As shown by the monthly data presented on pages 4 and 5 of Schedule 10, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.42 percentage points for the twelve-months ended October 2010. For the six- and three-month periods ending October 2010, the yield spread was 1.50% and 1.54%, respectively.

Beginning in August 2007, spreads widened significantly with the development of the credit crisis. As the credit crisis developed, there was a flight to quality, thereby increasing demand and reducing the yields on Treasury obligations. While this situation is most pronounced at the shortest end of the yield curve (i.e., obligations with the shortest duration), all Treasury yields display relatively low yields by reference to other credit obligations. By the end of 2009, the spread in yields on A-rated public utility bonds and 20-year Treasury bonds declined significantly from the peak of the credit crisis.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 12 provides the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When

> discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds. To take a balanced approach to the risk-free rate of return, the yield on long-term Treasury bonds has been used for this purpose.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors, which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns, which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 11 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in <u>Stocks, Bonds, Bills and Inflation</u> published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return, which divides the entire series of annual returns in half, and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. While the use of the geometric mean would be inappropriate for CAPM purposes due to the specification of that model, it can provide a limit of the bounds for the Risk Premium approach that does not contain the single-period limitation. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2007, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.82%	5.52%
Geometric Mean	4.23%	3.47%
Median	9.27%	7.50%
Midpoint of Range	6.75%	5.49%
Average of Arithmetic Mean and Midpoint of Range	6.29%	5.51%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 11 should also be considered. One of these sub-periods included the 56-year period, 1952-2007. These years follow the historic 1951 Treasury-Federal Reserve Accord, which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2007 and 1979 through 2007 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 56-year, 34-year and 29-year periods, the public utility risk premiums were 6.58%, 6.08%, and 6.37% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 11.

APPENDIX H TO DIRECT TESTIMONY OF PAUL R. MOUL

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium, which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line, which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

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To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\ (Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure, which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price, which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment, which has a beta less than 1.0, is considered to be less risky than the market.

The beta coefficient *("β")*, the one input in the CAPM application, which specifically applies to an individual firm, is derived from a statistical application, which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 12 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the October 29, 2010 edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 12) the total return on the universe of Value Line equities is:

			Median				Median
	Dividend		Appreciation				Total
	Yield		Potential				Return
As of October 29, 2010	2.1%	+	12.47%	(1)	=		14.57%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. That return is shown below.

DCF Result for the S&P 500 Composite							
D/P	(	1+.5g	)	+	g	=	k
1.89%	(	1.0547	)	+	10.94%	=	12.93%
where:		Price (P)		at	31-Oct-2010	=	1183.26
		Dividend (D)		for	3rd Qtr. '10	=	5.60
		Dividend (D)			annualized	=	22.40
		Growth (g)			First Call EpS	=	10.94%

Using these indicators, the total market return is 13.75% (14.57% + 12.93% = 27.50% ÷ 2) using both the Value Line and S&P derived returns. With the 15.16% forecast market return and the 4.25% risk-free rate of return, a 9.50% (13.75% - 4.25%) market premium would be indicated using forecast market data.

I have also provided market premiums that have been widely circulated among the investment and academic community, which today is published by Morningstar, Inc. These data are contained in the 2010 Ibbotson® Stocks, Bonds, Bills and Inflation ("SBBI") Classic Yearbook. From the data provided on page 6 of Schedule 12, I calculate a market premium using the historical common stock arithmetic mean returns of 11.8% less government bond arithmetic mean returns of 5.8%. For the period 1926-2009, the market premium was 6.0% (11.8% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it

[1] The estimated median appreciation potential is forecast to be 60% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 12.47% (i.e., $1.60^{.25}$ - 1).

is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. 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 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 their (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 their capital to the investment. (<u>Stocks, Bonds, Bills and Inflation</u> - 1996 Yearbook, pages 153-154)

Also shown on page 6 of Schedule 12 is the long-horizon expected market premiums of 6.7% also published in the <u>SBBI Classic Yearbook</u>. An average of the historical and expected SBBI market premium is 6.35% (6.0% + 6.7% = 12.7% ÷ 2).

For the CAPM, a market premium of 7.93% (6.35% + 9.50% = 15.85% ÷ 2) would be reasonable which is the average of the 6.35% <u>SBBI</u> data and the 9.50% <u>Value Line</u> and S&P 500 data.

APPENDIX I TO DIRECT TESTIMONY OF PAUL R. MOUL

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

> The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For

screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

<u>Price Stability Index</u>

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

<u>Beta</u>

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

CPG STATEMENT NO. 4 – PAUL J. SZYKMAN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
	:	
	:	
v.	:	Docket No. R-2010-2214415
	:	
UGI CENTRAL PENN GAS, INC.	:	
	:	

DIRECT TESTMONY
OF PAUL J. SZYKMAN

CPG Statement No. 4

Development of Historic and
Future Test Year Sales and Revenues, and
Proposed Rate Design

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Paul J. Szykman. My business address is 2525 North 12th Street, Reading, PA 19612-2677.

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

A. I am employed by UGI Utilities, Inc. as Vice President – Rates.

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President – Rates, I am responsible for all rate activities for UGI Utilities, Inc. – Gas Division ("UGI"), UGI Penn Natural Gas, Inc. ("PNG"), UGI Central Penn Gas, Inc. ("CPG") and UGI Utilities, Inc. – Electric Division ("UGIED"), specifically including sales and revenue forecasting, tariff administration and compliance, Choice administration, 1307(f) gas cost filings, electric POLR filings and Energy Efficiency & Conservation plans.

Q. What is your educational and professional background?

A. Please see my resume attached as CPG Exhibit PJS-1 hereto.

Q. Have you testified previously before this Commission?

A. Yes. Included within CPG Exhibit PJS-1 is a listing of those proceedings.

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

A. I will address several issues as part of my testimony: (1) the development of historic and future test year sales and revenues, (2) the standardization of CPG rate schedules with those found in both the UGI and PNG tariffs, and (3) CPG's proposed revenue allocation and rate design.

Q. Mr. Szykman, are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to CPG Exhibit PJS-1 mentioned above, I am sponsoring the following Exhibits: CPG Exhibit PJS-2 (15 year normal heating degree days), CPG Exhibit PJS-3 (Future Test Year Sales and Revenue Adjustments), CPG Exhibit PJS-4 (Historic Test Year Sales and Revenue Adjustments), CPG Exhibit PJS-5 (Rate NNS calculation), CPG Exhibit PJS-6 (Rate MBS calculation) and Schedules D-5A and D-5B of CPG Exhibit A. I am also sponsoring certain responses to the Commission's filing requirements. Each response identifies the witness sponsoring it. Specifically, I am sponsoring those schedules which were prepared by me or under my direction as appropriately identified in this filing.

II. <u>DEVELOPMENT OF HISTORIC AND FUTURE TEST YEAR SALES AND REVENUES</u>

A. Development of Future Test Year Sales and Revenues

Q. Please explain how the Company's future test year sales and revenues were developed.

A. Future test year sales and revenues were developed by annualizing the Company's 2011 fiscal year sales and revenue budget and by adjusting the budget to reflect the most recently available information. Annualized sales were determined by developing sales and revenue adjustments reflective of forecasted customer counts and annual expected use per customer as of September 30, 2011 for a full 12 month period. CPG's 2011 fiscal year sales and revenue budget reflects normal heating degree days of 6,408 based upon a 15 year period ending December 31, 2009. CPG Exhibit PJS-2 provides the supporting calculation of normal heating degree days.

Q. Has the Company updated its normal degree days since the CPG's last base rate case in 2009?

A. Yes, consistent with the Company's practice of updating normal heating degree days on a 5 year cycle, CPG recalculated its normal heating degree days for the period ending December 31, 2009. CPG's prior normal heating degree days, for the 15 year period ending December 31, 2004, were 6,318 by comparison..

Q. Please explain the process for developing the Company's 2011 fiscal year sales and revenue budget?

A. The sales and revenue budget is a joint effort of the Marketing and Rates Departments, with Marketing providing customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The Rates Department develops normalized usage per customer for core customer classes, annualized sales and total revenues. The budget process is described in the direct testimony of Mr. Brown (CPG St. No. 2). In developing sales and revenues, the Vice President of Marketing, with input and assistance from other marketing employees, budgets the number of customers by customer class. Various factors are considered in developing customer budgets, including the trend in losses and conversions to and from other energy sources, the level of applications and inquiries for service, new construction activity, current and projected economic factors and costs of competing fuels. The usage per customer reflected in the budget prepared by the Rates Department was initialized utilizing an econometric model which incorporates regression analysis of historic actual weather and actual usage per customer class to develop budget equations. Changes in customer mix within a rate class or unusual non-recurring usage trends were also considered, as well as management experience, in determining budget usage per customer. Budgeted numbers of customers and usage per customer for these customer classes are then combined to produce budgeted sales. Sales are allocated by month and appropriate rates/rate blocking is applied to derive budgeted revenues. Sales and revenues related to large customer classes (Rates GD and L) were developed by the Marketing Department on a customer specific basis in conjunction with customer input, as appropriate.

Q. Please describe the adjustments made to future test year sales and revenue for the 12 months ending September 30, 2011.

A. A summary of all adjustments made to the 2011 budget in order to develop fully adjusted future test year sales is shown on CPG Exhibit PJS-3(a). In total, these adjustments reflect a reduction to sales of 1,644 MDth and a reduction to revenue of $7.895 million, inclusive of revenues for recovery of PGC costs.

Q. Please explain the "Adjustment for Customer Changes" shown on CPG Exhibit PJS-3(a).

A. "Adjustment for Customer Changes" annualizes customer counts to anticipated end of test year levels based on the Company's most recent forecast for the future test year. In particular, this adjustment includes a net reduction of 1,337 residential heating customers and a net reduction of 357 commercial heating customers. CPG's actual beginning of test year customer counts along with CPG's most recent forecast for end of test year customer counts were used in developing this adjustment.

Q. How is this adjustment quantified?

A. CPG Exhibit PJS-3(b) provides the calculation of the associated sales and revenue adjustments for the stated customer count reductions. This adjustment reduces sales by 244 MDth and reduces projected revenues by $2.624 million, inclusive of revenues for recovery of PGC costs and exclusive of transportation customer adjustments discussed separately below.

Q. Please explain your next adjustment, "Adjustment for Annualized Use/Customer".

A. "Adjustment for Annualized Use/Customer" annualizes usage per customer to forecasted end of test year levels based upon a 5 year regression analysis of actual usage and degree day information for the period ending November 2010 and forecasting end of test year use per customer conditions using the regression results along with normal heating degree days. The calculations shown on CPG Exhibit PJS-3(c) quantify this adjustment, resulting in a net sales decrease of 456 MDth and a net revenue decrease of $4.096 million, inclusive of revenues for recovery of PGC costs and exclusive of transportation customer adjustments discussed separately below.

Q. Why did CPG utilize a regression period of 5 years?

A. A 5 year period was chosen in order to accurately capture recent trends in customer conservation over that same period, in part prompted by higher energy and consumer pricing, “green” and carbon reduction awareness actions, economic and environmental impacts. CPG utilizes an econometric regression model that incorporates four independent variables: customers, heating degree days, lagged heating degree days and time trend. While customers and heating degree days capture annualized usage factors based on forecasted annualized customer changes and weather defined to a normal standard, the time trend variable of this regression captures trends underlying changes in usage per customer over time. These trends can be varied, but as a comprehensive variable, “trend” will capture the impacts of conservation items and measures, including but not limited to, regular appliance replacements, accelerated appliance replacements, high efficiency appliance installations, setback thermostat installations, modifications to new and existing buildings which are designed to decrease energy consumption, changes in consumer usage behavior in response to energy price changes and other economic influences. Accordingly, given the number of variables which can influence customer usage over time, and the difficulty in identifying, quantifying and tracking all variables over time, the use of a trend variable acts as a comprehensive indicator of usage trends which can then be forecast for a future period.

Q. Is the econometric model you described the same as that utilized in CPG's last base rate case in 2009?

A. Yes, CPG has employed the same approach in both cases.

Q. Please explain the adjustment titled "Adjustment for Transport Changes" as shown on CPG Exhibit PJS-3(a).

A. "Adjustment for Transport Changes" is the summation of several adjustments made for CPG's transportation customers for the future test year. This adjustment reduces projected sales by 952 MDth and decreases revenues by $1.136 million, as shown in summary on CPG Exhibits PJS-3(b) and PJS-3(c) and detailed on CPG Exhibits PJS-3(b)(1) and PJS-3(c)(1). The basis for the portion of these adjustments relating to large transportation customers has been developed by CPG marketing personnel following review of individual large customer accounts and market segments and reflects anticipated increases or reductions in the sales and revenues of these accounts from original 2011 budget levels. This adjustment is explained in more detail in the Direct Testimony of Mr. Beard (UGI St. No. 1). Changes in customer counts for small transportation customer classes have been developed from CPG marketing forecasts for counts at the end of the future test year and associated use per customer adjustments have been developed utilizing the same 5 year regression method explained above for core retail customer classes.

Q. Does CPG Exhibit PJS-3(a) reflect an adjustment for lost sales associated with CPG's proposed Energy Efficiency & Conservation Plan?

A. No. As explained in the Direct Testimony of Mr. Lahoff in UGI Statement No. 5, the Company is proposing a separate rate recovery mechanism for the impact of lost sales as a result of those programs.

Q. Please explain the "Adjustment for PGC" shown on CPG Exhibit PJS-3(a).

A. The "Adjustment for PGC" shown in summary on CPG Exhibit PJS-3(a) represents an annualization of the future test year PGC gas cost revenues to the PGC rate as of December 1, 2010 for the test year period. CPG Exhibit PJS-3(d) provides the calculations for this adjustment. This adjustment increases PGC revenue for the test year by $0.947 million.

Q. Please explain the three adjustments shown on CPG Exhibit PJS-3(a), "Adjustment for MFC", "Adjustment for USP" and "Adjustment for STAS".

A. The "Adjustment for MFC" annualizes CPG's Merchant Function Charge revenues for the future test year based on the MFC surcharge rate as of December 1, 2010. The "Adjustment for USP" annualizes CPG's Universal

Service Programs surcharge revenues for the future test year based on the USP surcharge rate as of December 1, 2010. Additionally, the “Adjustment for STAS” reflects zeroing out the current CPG State Tax Adjustment Surcharge from its current level of 0.05%. The MFC adjustment increases projected revenues by $0.018 million. The USP adjustment reduces projected revenues by $0.494 million, and the STAS adjustment reduces projected revenues by $0.034 million. Additional detail on these three adjustments is provided on CPG Exhibits PJS-3(e), PJS-3(f) and PJS-3(g).

Q. Please explain the “Adjustment for Storage Transfer” shown on CPG Exhibit PJS-3(a).

A. The “Adjustment for Storage Transfer” reflects the adjustments to be made to base rates consistent with the Commission’s order at Docket No. P-2009-2145774, upon the transfer of existing CPG storage to UGI Storage Company. This transfer is projected to be effective on April 1, 2011. The associated revenue adjustment is a reduction of $0.558 million and is detailed on CPG Exhibit PJS-3(h).

Q. Do the adjusted Future Test Year revenues exclude the revenues related to off-system sales margins that are retained by the Company under the Commission approved off-system sales sharing mechanism?

A. Yes.

Q. Are there any other adjustments to Future Test Year revenues that have been made?

A. Yes. Revenues related to Rate O (Outdoor Lighting) have been added. These revenues were not included in the original budget and increase Future Test Year revenue by $0.082 million.

B. Development of Sales and Revenues – Historic Year

Q. How were annualized and normalized sales and revenue determined for the historic year ending September 30, 2010?

A. Actual sales and revenues serve as the starting point for the development of the annualized and normalized historic year sales and revenues presented in CPG Exhibit PJS-4(a). As shown on this exhibit, several adjustments were made to the historic year data in order to produce annualized and normalized sales and revenues. In total, these adjustments decrease sales by 287 MDth and decrease revenues by $12.168 million.

Q. Please explain the “Adjustment for Customer Changes” shown on CPG Exhibit PJS-4(a).

A. The “Adjustment for Customer Changes” annualizes customer counts to the customer levels as of the end of the historic year, or September 30, 2010. This results in a decrease in sales of 177 MDth and a decrease in revenues of $1.979 million, inclusive of revenues for recovery of PGC costs and exclusive of transportation customer adjustments discussed separately below. CPG Exhibit

PJS-4(b) details the associated changes in both sales and revenues resulting from this annualization of customers.

Q. Please explain the “Adjustment for Annualized Use/Customer” shown on CPG Exhibit PJS-4(a).

A. The “Adjustment for Annualized Use/Customer” annualizes usage per customer to normalized and annualized end of historic year levels. It is based upon the same 5 year regression analysis of usage and degree day information explained previously, as applied to the historic year period. For purposes of normalizing, normal heating degree days are based on the same 15 year average explained previously. The detailed calculations shown on CPG Exhibit PJS-4(c) quantify this adjustment, resulting in a net sales decrease of 256 MDth and a net revenue decrease of $2.683 million, inclusive of revenues for recovery of PGC costs and exclusive of transportation customer adjustments discussed separately below.

Q. Please explain the adjustment titled “Adjustment for Transport Customers” as shown on CPG Exhibit PJS-4(a).

A. “Adjustment for Transport Customers” is the summation of several adjustments made for CPG’s transportation customers for the historic year. This adjustment increases sales by 146 MDth and increases revenues by $0.624 million, as shown in summary on CPG Exhibits PJS-4(b) and PJS-4(c) and detailed on CPG Exhibits PJS-4(b)(1) and PJS-4(c)(1).

Q. Please explain the “Adjustment for PGC” shown on CPG Exhibit PJS-4(a).

A. This adjustment normalizes actual PGC revenues for the historic year to PGC rates in effect as of September 30, 2010. CPG Exhibit PJS-4(d) reflects the calculations supporting this adjustment, which results in a decrease in revenues of $1.373 million.

Q. Please explain the two adjustments shown on CPG Exhibit PJS-4(a), “Adjustment for MFC” and “Adjustment for USP”.

A. The “Adjustment for MFC” annualizes CPG’s Merchant Function Charge revenues for the historic year based on the MFC surcharge rate as of September 30, 2010. The “Adjustment for USP” annualizes CPG’s Universal Service Programs surcharge revenues for the historic year based on the USP surcharge rate as of September 30, 2010. The MFC adjustment decreases revenues by $0.026 million and the USP adjustment decreases projected revenues by $0.371 million. Additional detail on these two adjustments is provided on CPG Exhibits PJS-4(e) and PJS-4(f).

Q. Please explain the last adjustment shown on CPG Exhibit PJS-4(a) “Adjustment for Storage Removal”.

A. The “Adjustment for Storage Removal” annualized the impact of CPG” projected transfer of storage assets to UGI Storage Company in accordance with the Commission’s Order at Docket No. P-2009-2145774. This adjustment decreases revenue by $6.360 million.

III. PROPOSED STANDARDIZED RATES & RATE DESIGN

Q. Please describe the Company's approach to standardizing rate schedules for CPG.

A. As explained in the testimony of Mr. Lahoff, CPG St. No. 5, the Company is proposing, to the extent practicable, to align rate schedule designations with those found in currently effective, Commission-approved tariffs of UGI and PNG. CPG is undertaking this rate schedule standardization in order to achieve the goals of facilitating tariff administration, unifying internal and external communications and creating a common design in support of transportation service offerings across operating companies, which fosters greater competitive choices for customers. Accordingly, CPG's proposed Original Tariff No. 4 reflects standardization of rate schedules for Rate R (Residential Service), Rate N (Non-Residential Service), Rate DS (Delivery Service), Rate LFD (Large Firm Delivery Service), Rate XD (Extended Volume Large Delivery Service), Rate RT (Residential Transportation), Rate NT (Non-Residential Transportation) and Rate IS (Interruptible Transportation Service). Several other rate schedules are also being proposed, which are intended to replace other special service rate offerings currently provided by CPG. CPG's proposed Original Tariff No. 4 is set forth in CPG Exhibit F. As explained by Mr. Lahoff, a digest of changes to CPG's Original Tariff No. 4 are included with the tariff.

Q. Does CPG believe that standardizing rate schedules will serve to facilitate tariff and rate administration activities on the CPG system?

A. Yes. With these changes, all three UGI distribution companies, UGI, PNG and CPG, will have very similar rate schedules, along with associated transportation and balancing rules and procedures where applicable. This commonality should allow the UGI Companies and outside entities to become more efficient by utilizing common administrative processes and procedures across multiple UGI systems.

Q. Please describe the basic criteria for eligibility under the standardized rate schedules.

A. Rates R and RT, respectively, are the sales service and (choice) transportation service rate schedules for all residential customers. Rate N is the basic firm sales service rate schedule for all small commercial and industrial customers. Rate NT is the small firm (choice) transportation service rate schedule for non-residential customers. Rate DS is the basic transportation service rate schedule for non-residential customers and requires a minimum one year contract term. Rate LFD is a transportation service available to non-residential customers who entered into a contract for not less than three years and elect a Daily Firm Requirement ("DFR") of not less than 50 Mcf. Rate XD is a negotiated transportation service available to non-residential customers with annual requirements over 200,000 Mcf who execute a service agreement for a minimum of three years. Rate IS is a negotiated interruptible transportation service rate with a minimum term of one year.

Q. How are existing customers assigned to these new rate schedules in the proof of revenue presentation?

A. Existing customers are assigned as follows:

- All current Rate Schedule R (Residential Service) customers will become Rate R (Residential Service) customers;
- There are no current Rate Schedule RMD (Residential Monthly Delivery Service) customers, and any future residential transportation service customers will receive service under Rate RT (Residential Transportation Service);
- Rate Schedule G (General Service) customers have been assigned to Rate N (Non-Residential Service) with the exception of 56 Rate Schedule G customers who have been assigned to Rate DS (Delivery Service) and 32 Rate Schedule G customers who have been assigned to Rate LFD (Large Firm Delivery Service). These assignments were developed under the assumption that qualifying customers will make the most economical rate choice;
- All current Rate Schedule SGMD (Small General Monthly Delivery Service) customers have been assigned to Rate NT (Non-Residential Transportation Service);
- Rate Schedule GMD (General Monthly Delivery Service) customers have been assigned largely to Rate NT (Non-Residential Transportation Service) with the exception of 8 Rate Schedule GMD customers who have been assigned to Rate LFD (Large Firm Delivery Service), again under the assumption that qualifying customers will make the most economical rate choice;
- Rate Schedule GD (General Daily Delivery Service) customers have been assigned to several rate schedules as follows: 111 to Rate NT (Non-Residential Transportation Service), 103 to Rate DS (Delivery Service) and 99 to Rate LFD (Large Firm Delivery Service), under the assumption that qualifying customers will make the most economical rate choice;
- Rate Schedule L (Large Volume Daily Delivery Service) customers also have been assigned to several rate schedules as follows: 11 to Rate NT (Non-Residential Transportation Service), 10 to Rate DS (Delivery Service) 76 to Rate LFD (Large Firm Delivery Service) and 9 to Rate XD (Extended Large Volume Delivery Service), under the assumption that qualifying customers will make the most economical rate choice;
- Rate Schedule RS (Resale Service) customers have been assigned to Rate

N (Non-Residential Service), with the exception of 1 Rate Schedule RS customer who was assigned to Rate LFD (Large Firm Delivery Service) under the assumption that qualifying customers will make the most economical rate choice;

- Rate Schedule S (Storage Service) is a service available pursuant to executed service agreements wherein CPG agrees to receive and store gas in the Tioga West, Meeker and Wharton Storage Fields ("Storage Facilities") located in Potter, Cameron, and Tioga Counties in Pennsylvania. As explained by Mr. Lahoff (UGI St. No. 5), Rate Schedule S will no longer be available following FERC's issuance of a certificate of public convenience authorizing UGI Storage Company ("UGI Storage") to acquire the Storage Facilities and to own, operate and maintain them in interstate commerce, UGI Storage Company's acceptance of the certificate, and the actual transfer of the Storage Facilities from CPG to UGI Storage which is anticipated to occur on April 1, 2011. Accordingly, Rate Schedule S is being removed from Original Tariff No. 4;
- Rate Schedule O (Outdoor Lighting Service) customers are assigned to Rate GL (Gas Light Service);
- New Rate IS (Interruptible Service) is added with no projected customers. Rate IS will provide an alternative for current Rate SGMD, GMD, GD or L customers, or new customers who have a demonstrated alternate fuel capability;
- Rate Schedules DAB and MAB are being replaced with Rates NNS and MBS which will provide customers with balancing options that are functionally equivalent and are consistent with the balancing options contained in the UGI Gas and PNG tariffs.

A summary of all the above rate migrations under CPG's proposed Tariff No. 4 is provided as part of the Proof of Revenue presentation included as CPG Exhibit E.

Q. How will CPG effectuate these assignments to the new rate schedules?

A. The Company will undertake reasonable efforts to assign customers to the most economical rate, while at the same time maintaining the customer's existing service type (i.e., retail, choice or transportation).

As noted above, all residential customers currently taking service under

Rate Schedule R will automatically be moved to Rate R.

Rate Schedule G is CPG's current general service rate, and Rate Schedule RS is CPG's current rate schedule for Resale Service customers. Both Rate Schedules G and RS are retail rate schedules. The Company will perform rate evaluations for all Rate Schedule G and RS customers. Based upon our current assessment, the vast majority of Rate G and RS customers will be most economically served under Rate N, and the Company will automatically move these customers to Rate N. The Company does not intend to individually notify each of these customers of the change in rate schedules because Rate N is the basic retail rate for non-residential customers. If the Company determines that certain Rate G or RS customers could be more economically served under a new transportation rate (NT, DS, LFD or XD), the Company will send the customer a letter explaining the rate choices and what is required in order to select the more economic rate. The Company will not automatically enroll Rate R or GS customers on transportation rate schedules as these rate schedules require the election of an alternate supplier and require a written contract signed by the customer.

Rate Schedules SGMD and GMD are CPG's current choice rate schedules. The Company will perform a rate evaluation for all SGMD and GMD customers. If the customer's best economic alternative is a choice rate, CPG will send the customer a letter indicating that they will automatically be moved to Rate NT, the new choice rate, and that no action is required on their part. If the customer's best economic alternative is a non-choice transportation rate (DS, LFD or XD), CPG will send the customer a letter indicating the applicable rate options along with an explanation of what is needed to elect an alternate rate option. If no alternate rate election is made upon the effective date of the new rates, the Company will automatically serve the customer under Rate NT; and will coordinate this service with their existing choice supplier. The Company will not automatically assign existing choice customers to any non-choice transportation rate schedules without the customers' consent because, among other concerns, the non-choice transportation rate schedules require a written contract signed by the customer, have higher customer charges and require longer-term commitments.

Rate Schedules GD and L are CPG's existing non-choice transportation rate schedules. Similar to the evaluations performed above, CPG will perform a rate evaluation for all GD and L customers. If the customer's most economical alternative is a transportation rate (DS, LFD or XD), CPG will send the customer a letter indicating the details of their rate options and provide instructions on what is necessary in order to elect an alternative new rate. Should any customer not make an affirmative new rate election as of the effective date of the new rates, CPG will treat existing Rate GD and L agreements as Rate DS agreements until the stated end of such GD or L agreement, with DS rates being applied. At the end of the term of the GD or L agreement, if the customer has still not made an affirmative rate election, the customer will be provided continued service under Rate N. These customers will not be moved to a new transportation rate without their consent because the transportation rate schedules require written contracts, including a requirement to fully evaluate contract demand level and term conditions of service before choosing an appropriate transportation rate schedule.

III. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

Q. Is CPG proposing any rate design changes as part of this filing?

A. Yes. In addition to the rate offering changes identified above, CPG proposes to replace the current declining rate block structure for Rate Schedule R by a single block structure under Rates R and RT. The elimination of a declining rate block structure is consistent with CPG's settlement obligation from CPG's last rate case. Additionally, CPG is eliminating the $2.5 million acquisition settlement credit in accordance with CPG's acquisition settlement obligation.

Q. What is the primary goal of the transportation service proposals found in CPG Original Tariff No. 4?

A. The rate schedules currently offered by CPG, especially with respect to transportation service, are not well defined by customer size or usage characteristics. As a result, customers can elect different rate schedules for service, without substantial restriction. This affects the ability to develop differentiated "cost based" rates for the commercial and industrial rate schedules. CPG's goal is to modify transportation service offerings in a manner which promotes the expanded use of transportation services on the CPG system by all customers, yet provides the appropriate mechanisms to maintain appropriate distribution system management and reliability through reasonable cost allocations, operational controls and procedures.

Q. Do you believe the changes proposed by CPG will achieve this goal?

A. Yes. There are several key proposals which will help achieve this goal:

- Restructuring the current non-choice transportation rate schedules into three separate rate schedules of DS, LFD and XD creates more distinct class cost of service categories and offers CPG and its customers the rate flexibility to negotiate terms and conditions with very large customers having a variety of competitive alternatives. As a result, 88 current retail customers representing in excess of 0.5 Bcf of annual usage are represented in this filing as new transportation customers;
- Offering optional balancing service elections under Rates NNS and MBS will expand the current limited daily and monthly balancing tolerances to tolerances that customers and Natural Gas Suppliers (“NGSs”) should find more flexible, fair and attractive;
- Implementing a system management concept which employs Critical versus Non-Critical Day designations providing for commensurate changes in overrun charges. This will make inadvertent Non-Critical Day overruns less burdensome for customers and NGSs, and at the same time, provide an additional safeguard against intentional system arbitrage that could negatively impact system reliability; adopting similar rules and procedures for residential and small commercial “choice” transportation that currently exist on the UGI and PNG systems will allow the NGSs who are currently active and serving in excess of 20,000 customers on the UGI and PNG systems to readily utilize existing communication protocols with UGI on the CPG system;
- Aligning rate schedule designations with those found in the current UGI and PNG tariffs will promote communication efficiencies across these UGI systems for customers, NGSs, and UGI personnel; and
- Establishing a Cash-Out mechanism which is based on a published local market index will provide for greater transparency and equity compared to the current Cash-Out pricing structure.

Q. How does CPG plan to communicate these changes to transportation customers and NGSs regarding the need to make new transportation service elections under proposed rates?

A. Similar to the methodology employed by PNG, CPG plans to use a communication program to provide notice to all current transportation customers, and those Schedule G (General Service) customers who have been identified as having more economical alternatives on the new non-choice transportation rates, in order to inform those customer of the new customer rate options and communicate the effects on an individual customer basis. Additionally, as part of continued tariff collaborative activities with NGSs, CPG will work to educate NGSs on new tariff rate and service offerings and develop coordinated communications designed to produce a smooth transition to the new proposed changes. Because CPG has, in large part, adopted the Choice Supplier Tariff used by UGI, which was also adopted by PNG in its last base rate case at Docket No. R-2008-2079660, CPG believes that the standardization of the three Choice Supplier Tariffs should make it easier for suppliers to provide service and should foster greater competitive choices for customers.

Q. Please summarize CPG's rate design and allocation of the revenue increase ratemaking philosophy.

A. CPG's ratemaking goal is to implement reasonable rates that recover our cost of doing business. Rate schedules are generally designed to reflect movement toward class cost of service and to be competitive with prices of alternate energy sources, including bypass. Our rates and rate design seek to achieve efficient utilization of CPG's facilities and natural gas supplies.

Q. What factors has CPG considered in establishing its rate structure?

A. The Company considers cost of service as the primary factor in determining revenue allocation and rate design. Other factors that are considered include competition, historic rate patterns, supply conditions, impacts upon customers, the local economy, the nature of our territory, the needs of our customers, utilization of facilities, and public acceptance of rate forms and changes.

Q. Please describe the proposed distribution of the revenue increase among customer classes.

A. Overall, CPG is proposing to move all rate classes to, or substantially toward, cost of service while not allowing any increase to exceed a level of twice the system average increase. In measuring cost of service, the Company relies on Mr. Herbert's to prepare a cost of service study which uses the Average and Excess Method for allocating distribution mains. This method is an accepted cost allocation method, and CPG used this method in its last base rate proceeding.

As evidenced by the cost of service study presented by Mr. Herbert, under present rates, the Residential class is producing a return of 3.84% as compared to a system average return of 5.02%. This translates to a relative rate of return of 0.76 compared to the system average. In allocating revenues, CPG proposes to move the residential class to cost of service, resulting in an allocation of $11.0 million of the revenue increase to the residential customer group. At this level, Rate R rates will produce an overall return of 9.11%, equal to the proposed system average return of 9.11%. This translates to a relative rate of return of 1.0.

For Rate N, the small commercial retail customers, current rates are producing a return of 3.02% with a relative rate of return of 0.60. CPG proposes to allocate $5.0 million of the revenue increase to Rate N customer group (Rates N and NT) in order to move the Rate N class to cost of service at an overall return of 9.09%, or a relative rate of return of 1.0.

For Rate DS, the transportation rate for small to medium sized customers, current rates are producing a return of 1.43% with a relative rate of return of 0.28. CPG proposes to allocate approximately $1.5 million of the revenue increase to Rate DS customers in order to produce a class return of 7.44%, or a relative rate of return of 0.82. This movement toward cost of service is consistent with CPG's proposal to move all customer classes toward cost of service, but not in a manner which would result in an increase greater than twice the system average.

For Rate LFD, the transportation rate for medium to large sized customers, current rates are producing a return of 9.87%, with a relative rate of return of 1.97. CPG proposes to decrease rates for LFD customers by approximately $0.2 million in order move this customer class to cost of service; producing an overall return of 9.11%, or a relative rate of return of 1.00.

For Rate XD, the transportation rate for large competitive customers, current rates are producing a return of 14.71%, with a relative rate of return of 2.93. CPG proposes to decrease rates for the Rate XD class by approximately $0.8 million. This proposed change will move this class to a 10.86% return, with a relative rate of return of 1.19. This decrease represents substantial movement of this highly competitive customer class toward system average rate of return.

Q. Do you believe it is reasonable to move all classes substantially toward, or to, cost of service in this proceeding?

A. Yes, I do. I have been advised by counsel that the Commonwealth Court has held that a class cost of service study should be the guiding principle for allocating revenue to different customer classes. *Lloyd v. Pa.P.U.C.*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006). Consistent with the *Lloyd* decision, CPG has proposed to move all classes to, or substantially toward, their respective class cost of service in this proceeding. Moreover, in moving three of CPG's five customer classes to cost of service, and measuring against CPG's goal of not having any customer class exceed an increase of twice that of the total system average increase, the resulting increases are not unreasonable or disparate.

Q. Please describe the rate design modification for Rate R included in proposed CPG Original Tariff No. 4.

A. As explained above, all current Rate Schedule R (Residential Service) customers will continue to be Rate R (Residential Service) customers. CPG is eliminating declining blocks for Rate R customers and proposing to increase the customer charge for Rate R. Because of these changes, certain Rate R customers will experience less than the average increase and others will experience more than the average increase. The residential customer charge has been increased to

$20.00 per month. CPG's proposed customer charges reflect effectively 100% of customer costs, as shown on the customer component of cost of service, detailed in CPG Exhibit D.

Q. Please explain the addition of a proposed Standby service for Rate R.

A. To accommodate service to customers who choose to install natural gas as a backup heating fuel to another fuel source, the Company has developed a Standby Surcharge consistent with the cost of providing this service. Presently, backup or standby customers utilize gas service occasionally, mostly during high cost peak demand periods. The Standby component added to Rate R recognizes the need to recover the cost of serving these customers with lower sales volumes.

Q. Please describe the proposed rate design changes for Rate N.

A. As explained above, with the exception of 56 Rate Schedule G customers who have been reflected as Rate DS (Delivery Service) customers and 32 Rate Schedule G customers who have been reflected as Rate LFD (Large Firm Delivery Service) customers, the existing Rate Schedule G (General Service) customers will become Rate Schedule N (Non-Residential Service) customers. CPG is not proposing an increase in customer charges for Rate N customers because once the Acquisition Settlement Credit is removed from current customer charge rates, the Rate N customer charge is $26.00, a level slightly lower than that supported by the direct customer component of cost of service.

The Company also is proposing a Standby service for Rate N similar to that proposed for Rate R.

Q. Please describe the proposed rate design for Rate DS.

A. As noted above, Rate DS is a transportation rate applicable to small to medium sized transportation customers. The DS rate schedule is modeled after the DS rate schedule contained in the tariffs of UGI and PNG, providing a non-choice transportation service offerings for these small to medium sized customers. The customer charge for Rate DS has been established at a level approximately equal to the direct customer component cost of service.

Q. Please describe the proposed rate design for Rate LFD.

A. The LFD rate schedule is designed to offer transportation service to medium to large sized customers. This rate schedule is modeled off of the UGI and PNG LFD rate schedule and requires a minimum daily requirement of 50 Mcf and a three-year term. The customer charge for Rate LFD has been established at a level approximately equal to the direct customer component cost of service.

Q. Please describe the proposed rate design for Rate XD.

A. Rate XD was also modeled after Rate XD found in UGI and PNG tariffs. This negotiable rate schedule is designed for high usage, high load factor transportation customers. It has an annual requirement of 200,000 Mcf and a minimum three-year term. The maximum distribution charge for Rate XD has been established at a level equal to the maximum distribution charge for Rate LFD.

Q. Please describe the proposed rate design for Rate NNS.

A. Rate NNS (No Notice Service) is a daily balancing service which CPG has patterned off the current Rate NNS offered by UGI and PNG to transportation customers. It provides an alternate election of daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard 2.5%. A customer is able to make a Rate NNS election up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen.

Q. How were the proposed NNS rates developed?

A. The charge for providing service under Rate NNS is a monthly charge established using CPG's total weighted average cost of interstate storages that can be utilized for balancing excess or shortfall requirements of the CPG system. CPG Exhibit PJS-5 shows the calculation of the Rate NNS charge, which was developed based upon the Company's cost to provide this service following the same rate design methodology utilized by UGI and PNG. The proposed rate for NNS service is $1.64/Mcf of demand ("Mcfd").

Q. Please describe the rate design for proposed Rate MBS.

A. Rate MBS is a monthly balancing service which CPG has patterned off of the current Rate MBS offered by UGI and PNG to transportation customers. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excesses or receipt of shortfalls in subsequent months.

Q. How were the proposed MBS rates developed?

A. CPG Exhibit PJS-6 provides the basis for the Rate MBS calculations, as well as the proposed MBS rates under Rates DS, LFD and XD. These rates also were developed based upon CPG's costs to provide MBS service following the same rate design methodology utilized by UGI and PNG.

Q. Are the revenues received from Rates NNS and MBS proposed to be credited to PGC rates?

A. Yes, revenues from these rate schedules are proposed to be credited to the PGC.

Q. Please describe the Company's rate structure considerations as related to its proposed Rate IS (Interruptible Transportation Service).

A. CPG will negotiate individual arrangements with customers who desire to have transportation service that can be interrupted at the Company's discretion, based upon the Company's judgment as to system needs, the customer's service level and financial preferences, and CPG's investment criteria for the customer's specific competitive conditions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CPG EXHIBIT NOS. – PJS-1 THROUGH 6

PAUL J. SZYKMAN

VICE PRESIDENT – RATES

October 2008 – Present	Vice President – Rates UGI Utilities, Inc., Reading, PA
2003 – 2008	Director, Rates & Gas Supply UGI Utilities, Inc., Reading, PA
2001 – 2003	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1999 – 2001	Manager, Federal Regulatory Affairs & Contract Admin. UGI Utilities, Inc., Reading, PA
1999 – 1999	Principal AMS, Fairfax, VA
1996 – 1999	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1994 – 1996	Supervisor, Transportation UGI Utilities, Inc., Reading, PA
1991 – 1994	Rate Designer UGI Utilities, Inc., Reading, PA
1989 – 1991	Market Research Analyst UGI Utilities, Inc., Reading, PA
1986 – 1989	Industrial / Commercial Representative UGI Utilities, Inc., Reading, PA
1981 – 1985	Penn State University B.S. Mechanical Engineering

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

R-00932927, R-00016376, R-00016376C0002, P-00032043,
P-00032054, R-00049422, R-00050539, R-00061502, R-00072334,
R-00072335, R-2008-2039284,R-2008-2039417, R-2008-2079675,
R-2008-2079660, R-2009-2105911, R-2009-2105904 and R-2009-2105909.

CPG Exhibit PJS-2

Annual Heating Degree Days [1]
UGI Central Penn Gas, Inc. ("CPG")

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		15 Yr. Avg.
HDD	6,576	6,579	6,650	5,458	6,114	6,524	6,129	6,175	6,850	6,560	6,663	5,938	6,523	6,696	6,689		**6,408**

[1] Annual Heating Degree Days are accumulated on a gas day basis (10:00am ECT to 10:00am ECT) for the period January 1 through December 31.

Future Test Year Sales and Revenues
Summary of Adjustments

	Sales (000's Dth)	Revenue ($000's)	Reference
Budget 2011	21,652	$114,424	
Adjustment for Customer Changes	(244)	(2,624)	CPG Exhibit PJS-3(b)
Adjustment for Annualized Use/Customer	(456)	(4,096)	CPG Exhibit PJS-3(c)
Adjustment for Transport Changes	(952)	(1,136)	CPG Exhibit PJS-3 (b)(1)/(c)(1)
Adjustment for PGC	0	947	CPG Exhibit PJS-3(d)
Adjustment for MFC	0	18	CPG Exhibit PJS-3(e)
Adjustment for USP	0	(494)	CPG Exhibit PJS-3(f)
Adjustment for STAS	0	(34)	CPG Exhibit PJS-3(g)
Adjustment for Storage Transfer	0	(558)	CPG Exhibit PJS-3(h)
Adjustment for Outdoor Lighting	7	82	CPG Exhibit E
Fully Adjusted Future Test Year	20,008	$106,529	

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] Commercial-Non Htg	[4] Commercial-Htg	[5] Industrial	[6] Transport-Other	[7] Total
1	Total Test Year Revenues(Unadjusted)	$ 1,407	$ 66,037	$ 1,625	$ 23,585	$ 2,702	$ 19,068	$ 114,424
2	PGC Revenues	(411)	(29,828)	(943)	(14,012)	(1,719)	-	(46,913)
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 996	$ 36,209	$ 682	$ 9,573	$ 983	$ 19,068	$ 67,511
4	Average Effective Customers in Test Year(Unadjusted)	3,804	61,582	708	7,886	146	1,038	75,164
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.262	$ 0.588	$ 0.963	$ 1.214	$ 6.732	$ 18.370	$ 0.898
6	Future Test Year Customers (Fully Adjusted)	3,685	60,245	698	7,529	143	1,345	73,645
7	Change in Customers Related to Adjustment (L 6 - L 4)	(119)	(1,337)	(10)	(357)	(3)	307	(1,519)
8	Annualization Adjustment for Margin (L 5 * L 7)	$ (31)	$ (786)	$ (10)	$ (433)	$ (20)	$ (145)	$ (1,425)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.370	$ 1.072	$ 2.295	$ 2.991	$ 18.505	$ 18.370	$ 1.522
10	Annualization Adjustment for Total Revenue (L 7 * L9)	$ (44)	$ (1,434)	$ (23)	$ (1,068)	$ (56)	$ (145)	$ (2,769)
11	Annualization Adjustment for PGC Revenues (L 10 - L8)	$ (13)	$ (648)	$ (13)	$ (634)	$ (35)	$ -	$ (1,343)
12	Total UPC (Unadjusted)-DTH	19.2	86.8	241.3	326.4	2152.1		
13	Annualization Adjustment for Sales-MDTH (L12 * L7)	(2)	(116)	(2)	(117)	(6)	(318)	(562)

Notes:
Column [4] includes Com Sales for Resale
Column [6] further detailed on CPG Exhibit PJS-3(b)(1)

CPG Exhibit PJS-3 (b)(1)

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for Customer Changes-Transport Detail

Line #	Description	[1] Commmercial-SGMD	[2] Commercial-GMD	[3] Industrial-GMD	[4] GDS/LDS	[5] Total Transport
1	Total Test Year Revenues(Unadjusted)	$ 266	$ 1,455	$ 8	$ 17,340	$ 19,068
2	PGC Revenues	-	-	-	-	-
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 266	$ 1,455	$ 8	$ 17,340	$ 19,068
4	Average Effective Customers in Test Year(Unadjusted)	255	442	2	339	1,038
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 1,043	$ 3,291	$ 3,889	$ 51,150	$ 18,370
6	Future Test Year Customers (Fully Adjusted)	393	617	2	333	1,345
7	Change in Customers Related to Adjustment (L 6 - L 4)	138	175	-	(6)	307
8	Annualization Adjustment for Margin	$ 144	$ 576	$ -	$ (865)	$ (145)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 1,043	$ 3,291	$ 3,889	$ 51,150	$ 18,370
10	Annualization Adjustment for Total Revenue	$ 144	$ 576	$ -	$ (865)	$ (145)
11	Annualization Adjustment for PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total UPC (Unadjusted)-DTH	269.9	1082.2	1155.4		
13	Annualization Adjustment for Sales-MDTH (L7*L12)	37	189	-	(545)	(318)

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

CPG Exhibit PJS-3 (c)

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] Commercial-Non Htg	[4] Commercial-Htg	[5] Industrial	[6] Transport-Other	[7] Reconciliation Adj *	[8] Total
1	Total UPC (Unadjusted)-DTH	19.2	86.8	241.3	326.4	2,152.1			
2	Future Test Year UPC (Fully Adjusted)-DTH	18.9	84.5	232.3	292.8	1,908.5			
3	Change in UPC-DTH (L 1 - L 2)	(0.3)	(2.3)	(9.0)	(33.6)	(243.6)			
4	Future Test Year Customers (Fully Adjusted)	3,685	60,245	698	7,529	143	1,345		73,645
5	Annualization Adjustment for Sales-MDTH	(1)	(139)	(6)	(253)	(35)	(634)	(22)	(1,090)
6	Annualization Adjustment for Total Revenue (L5 * L7)	$ (11)	$ (1,445)	$ (53)	$ (2,138)	$ (294)	$ (991)	$ (154)	$ (5,087)
7	Unit Revenue	10.43	10.43	8.45	8.45	8.45	1.56		
8	Annualization Adjustment for Margin (L5 * L9)	$ (5)	$ (674)	$ (18)	$ (740)	$ (102)	$ (991)	$ (22)	$ (2,552)
9	Unit Margin	4.86	4.86	2.92	2.92	2.92	1.56		
10	Annualization Adjustment for PGC Revenue (L6 - L8)	$ (6)	$ (771)	$ (35)	$ (1,399)	$ (193)	$ -	$ (132)	$ (2,535)

Notes:
Column [4] includes Com Sales for Resale
Column [6] further detailed on CPG Exhibit PJS-3(c)(1)
* Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for Annualized Use/Customer-Transport Detail

Line #	Description	[1] Commmercial-SGMD	[2] Commercial-GMD	[3] Industrial-GMD	[4] GDS/LDS	[5] Total Transport
1	Total UPC (Unadjusted)-DTH	269.9	1,082.2	1,155.4		
2	Future Test Year UPC (Fully Adjusted)-DTH	237.6	1,031.8	1,149.7		
3	Change in UPC-DTH (L 1 - L 2)	(32.3)	(50.4)	(5.7)		
4	Future Test Year Customers (Fully Adjusted)	393	617	2	333	1,345
5	Annualization Adjustment for Sales-MDTH	(13)	(31)	(0)	(590)	(634)
6	Annualization Adjustment for Total Revenue	$ (37)	$ (287)	$ (0)	$ (667)	(991)
7	Unit Revenue	2.92	9.23	2.07	1.13	1.56
8	Annualization Adjustment for Margin	$ (37)	$ (287)	$ (0)	$ (667)	(991)
9	Unit Margin	2.92	9.23	2.07	1.13	1.56
10	Annualization Adjustment for PGC Revenue (L6 - L8)	$ -	$ -	$ -	$ -	$ -

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for PGC

	OCT 2010	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	TOTAL
Original Budget PGC Rate R	$6.9993	$6.9993	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	
Future Test Year PGC Rate R	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	
PGC Rate R Variance	($1.4357)	($1.4357)	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	
Original Budget PGC Rate G	$6.9993	$6.9993	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	
Future Test Year PGC Rate G	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	
PGC Rate G Variance	($1.4709)	($1.4709)	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	
Total Original Budget PGC Volumes	277	643	1,155	1,472	1,395	1,352	960	470	250	176	164	184	8,500
Revenue Variance	($401)	($932)	$348	$443	$420	$407	$290	$142	$75	$53	$49	$55	$947

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for MFC

	OCT 2010	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	TOTAL
Original Budget PGC Rate R	$6.9993	$6.9993	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	
Future Test Year PGC Rate R	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	$5.5636	
PGC Rate R Variance	($1.4357)	($1.4357)	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	$0.3136	
Original Budget PGC Rate G	$6.9993	$6.9993	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	$5.2500	
Future Test Year PGC Rate G	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	$5.5284	
PGC Rate G Variance	($1.4709)	($1.4709)	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	$0.2784	
Total Original Budget PGC Volumes	81	185	348	467	443	417	282	135	65	53	49	57	8,500
Rate R %	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	
Rate G %	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	
MFC Rate R Adj Rate	($0.0373)	($0.0373)	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	$0.0082	
MFC Rate G Adj Rate	($0.0021)	($0.0021)	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
Revenue Variance	($7)	($16)	$6	$8	$7	$7	$5	$3	$1	$1	$1	$1	$18

CPG Exhibit PJS-3 (f)

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for USP

Cost of Goods Adjustment	
Original COG Revenue (Residential)	$30,239
Less USP Revenue	($679)
Adjusted COG Revenue(Residential)	$29,560
Base Revenue Adjustment	
Effective Future Test Year USP Rate	$0.0358
Fully Adjusted Rate R Volumes-MDTH	5,160
Adjusted Revenue for USP	$185
Net USP Revenue Adjustment	($494)

CPG Exhibit PJS-3 (g)

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for STAS

	OCT 2010	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	2011 TOTAL
RES. G	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
H	(1)	(2)	(2)	(3)	(3)	(3)	(2)	(1)	(1)	(1)	(1)	(1)	(19)
TOTAL R	(1)	(2)	(2)	(3)	(3)	(3)	(2)	(1)	(1)	(1)	(1)	(1)	(20)
COM. G	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
H	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(7)
SUBTOTAL COM	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(8)
SGMD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
GMD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
LDS	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
GDS	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
TOTAL COM	(0)	(1)	(1)	(2)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(10)
IND. G	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
H	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL IND	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
SGMD	0	0	0	0	0	0	0	0	0	0	0	0	0
GMD	0	0	0	0	0	0	0	0	0	0	0	0	0
LDS	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)
GDS	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
TOTAL IND	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(4)
GRAND TOTAL	(2)	(3)	(4)	(5)	(5)	(5)	(3)	(2)	(1)	(1)	(1)	(1)	(34)

UGI Central Penn Gas, Inc.
Future Period - 12 Months Ended September 30, 2011
($ in Thousands)

Adjustment for Storage Transfer

	OCT 2010	NOV 2010	DEC 2010	JAN 2011	FEB 2011	MAR 2011	APR 2011	MAY 2011	JUN 2011	JUL 2011	AUG 2011	SEP 2011	TOTAL
Rate R Customer Charge Reduction	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	
Rate R Distribution Charge Reduction	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	($0.0431)	
Rate G Customer Charge Reduction	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	($0.43)	
Rate G Distribution Charge Reduction	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	($0.0489)	
Rate GD Customer Charge Reduction	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	($2.41)	
Rate L Customer Charge Reduction	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	($21.50)	
Total Customers Fully Adjusted Budget	73,252	73,252	73,252	73,252	73,252	73,252	73,252	73,252	73,252	73,252	73,252	73,252	
Total Sales Fully Adjusted Budget	283	638	1,131	1,433	1,358	1,323	950	477	265	194	183	202	8,437
Distribution Charge Reduction	($11)	($26)	($47)	($60)	($57)	($56)	($40)	($20)	($11)	($8)	($7)	($8)	($351)
Customer Charge Reduction	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($17)	($206)
Total Distribution & Customer Reduction	($28)	($43)	($65)	($77)	($74)	($73)	($57)	($37)	($28)	($25)	($25)	($25)	($558)

Historic Year Sales and Revenues
Summary of Adjustments

	Sales(000's) DTH	Revenue ($000's)	Reference
Actual 2010	22,214	$126,614	
Adjustment for Customer Changes	(177)	(1,979)	CPG Exhibit PJS-4(b)
Adjustment for Annualized Use/Customer	(256)	(2,683)	CPG Exhibit PJS-4(c)
Adjustment for Transport Customers	146	624	CPG Exhibit PJS-4 (b)(1)/(c)(1)
Adjustment for PGC	0	(1,373)	CPG Exhibit PJS-4(d)
Adjustment for MFC	0	(26)	CPG Exhibit PJS-4(e)
Adjustment for USP	0	(371)	CPG Exhibit PJS-4(f)
Adjustment for Storage Removal	0	(6,360)	CPG Exhibit PJS-4(b)
Fully Adjusted Historic Year	21,927	$114,446	

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] Commercial-Non Htg	[4] Commercial-Htg	[5] Industrial	[6] Transport-Other	[7] Storage	[8] Total
1	Total Historic Year Revenues	$ 1,471	$ 69,338	$ 1,891	$ 25,295	$ 3,349	$ 18,909	$ 6,360	$ 126,614
2	PGC Revenues	(444)	(32,466)	(1,153)	(15,427)	(2,149)	207	-	(51,433)
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 1,027	$ 36,871	$ 738	$ 9,867	$ 1,201	$ 19,117	$ 6,360	$ 75,181
4	Average Effective Customers in Historic Year	4,011	61,726	750	8,136	160	1,145		75,928
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.256	$ 0.597	$ 0.984	$ 1.213	$ 7.503	$ 16.696		$ 0.990
6	Number of Customers at End of Year	3,930	60,781	741	7,905	153	1,314		74,824
7	Change in Customers during Historic Year (L 6 - L 4)	(81)	(945)	(9)	(231)	(7)	169	-	(1,104)
8	Annualization of Margin (L 5 * L 7)	$ (21)	$ (564)	$ (9)	$ (280)	$ (53)	$ 254	$ -	$ (673)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.367	$ 1.123	$ 2.522	$ 3.109	$ 20.934	$ 16.515		$ 1.668
10	Annualization of Total Revenue (L 7 * L9)	$ (30)	$ (1,062)	$ (23)	$ (718)	$ (147)	$ 573	$ -	$ (1,406)
11	Annualization of PGC Revenues (L 10 - L8)	$ (9)	$ (497)	$ (14)	$ (438)	$ (94)	$ 319	$ -	$ (733)
12	Total UPC (Unadjusted)-DTH	18.15	87.64	249.86	320.85	2,363.92			
13	Annualization Adjustment for Sales-MDTH (L12 * L7)	(1)	(83)	(2)	(74)	(17)	116	-	(61)

Notes:
Column [3] includes Com GL
Column [4] includes Com Sales for Resale
Column [6] further detailed on CPG Exhibit PJS-4(b)(1)

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for Customer Changes-Transport Detail

Line #	Description	[1] Commmercial-SGMD	[2] Commercial-GMD	[3] Industrial-GMD	[4] GDS/LDS	[5] Total Transport
1	Total Historic Year Revenues	$ 252	$ 1,434	$ 7	$ 17,217	$ 18,909
2	PGC Revenues	-	304	-	(96)	207
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 252	$ 1,738	$ 7	$ 17,121	$ 19,117
4	Average Effective Customers in Historic Year	266	534	2	343	1,145
5	Average Annual Margin Per Customer	$ 1.213	$ 1.213	$ 1.213	$ 49.914	$ 16.696
6	Number of Customers at End of Year	387	581	2	344	1,314
7	Change in Customers Related to Adjustment (L 6 - L 4)	121	47	-	1	169
8	Annualization Adjustment for Margin (L 5 * L 7)	$ 147	$ 57	$ -	$ 50	$ 254
9	Average Annual Revenue Per Customer	$ 3.109	$ 3.109	$ 3.109	$ 50.195	$ 16.515
10	Annualization Adjustment for Total Revenue (L 7 * L9)	$ 376	$ 146	$ -	$ 50	$ 573
11	Annualization Adjustment for PGC Revenues (L 10 - L8)	$ 229	$ 89	$ -	$ 0	$ 319
12	Total UPC (Unadjusted)-DTH	269.9	968.2	1230.4		
13	Annualization Adjustment for Sales-MDTH (L7*L12)	33	46	-	38	116

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] Commercial-Non Htg	[4] Commercial-Htg	[5] Industrial	[6] Transport-Other	[7] Total
1	Total FY 10 Actual UPC-DTH	18.15	87.64	249.86	320.85	2,363.92		
2	Fully Adjusted FY10 UPC-DTH	18.41	85.87	244.78	310.39	1,948.24		
3	Change in UPC -DTH (L 1 - L 2)	0.26	(1.77)	(5.08)	(10.46)	(415.68)		
4	End of Year Customers FY 10	3,930	60,781	741	7,905	153	1,314	74,824
5	Annualization Adjustment for Sales-MDTH	1	(107)	(4)	(83)	(64)	30	(226)
6	Total Revenue Adjustment (L5 *L7)	$ 13	$ (1,207)	$ (37)	$ (820)	$ (631)	$ 52	$ (2,632)
7	Unit Revenue Adjustment	12.48	11.25	9.92	9.92	9.92	1.72	
8	Margin Adjustment (L5 *L9)	$ 6	$ (456)	$ (11)	$ (242)	$ (186)	$ 52	$ (837)
9	Unit Margin	5.48	4.25	2.92	2.92	2.92	1.72	
11	PGC Revenue (L 6 - L8)	$ 7	$ (751)	$ (26)	$ (579)	$ (445)	$ -	$ (1,794)

Notes:
Column [3] includes Com GL
Column [4] includes Com Sales for Resale
Column [6] further detailed on CPG Exhibit PJS-4(c)(1)

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for Annualized Use/Customer-Transport Detail

Line #	Description	[1] Commmercial-SGMD	[2] Commercial-GMD	[3] Industrial-GMD	[4] GDS/LDS	[5] Total Transport
1	Total FY 10 Actual UPC-DTH	269.9	968.2	1,230.4		
2	Fully Adjusted FY10 UPC-DTH	237.9	1,041.4	1,177.5		
3	Change in UPC-DTH (L 1 - L 2)	(31.9)	73.2	(52.8)		
4	End of Year Customers FY 10	387	581	2	344	1,314
5	Annualization Adjustment for Sales-MDTH	(12)	43	(0)	-	30
6	Annualization Adjustment for Total Revenue (L5 *L7)	$ (36)	$ 88	$ (0)	-	52
7	Unit Revenue	2.92	2.07	2.07	-	1.72
8	Annualization Adjustment for Margin	$ (36)	$ 88	$ (0)	-	52
9	Unit Margin	2.92	2.07	2.07	-	1.72
10	Annualization Adjustment for PGC Revenue	$ -	$ -	$ -	-	$ -

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for MFC

	OCT 2009	NOV 2009	DEC 2009	JAN 2010	FEB 2010	MAR 2010	APR 2010	MAY 2010	JUN 2010	JUL 2010	AUG 2010	SEP 2010	TOTAL
PGC Rate FY 10	$6.8720	$6.8720	$6.8720	$6.8720	$6.8720	$7.7174	$7.9992	$7.9992	$7.2493	$6.9993	$6.9993	$6.9993	
Sept 10 PGC Rate	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	
PGC Rate Variance	$0.1273	$0.1273	$0.1273	$0.1273	$0.1273	($0.7181)	($0.9999)	($0.9999)	($0.2500)	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	627	574	1,041	1,789	1,548	1,276	689	422	226	167	139	182	8,680
Rate R %	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	
Rate G %	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	
MFC Rate R Adj Rate	$0.0033	$0.0033	$0.0033	$0.0033	$0.0033	($0.0187)	($0.0260)	($0.0260)	($0.0065)	$0.0000	$0.0000	$0.0000	
MFC Rate G Adj Rate	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	($0.0010)	($0.0014)	($0.0014)	($0.0003)	$0.0000	$0.0000	$0.0000	
Revenue Variance	$1	$1	$2	$4	$3	($16)	($12)	($8)	($1)	$0	$0	$0	($26)

CPG Exhibit PJS-4 (d)

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for PGC

	OCT 2009	NOV 2009	DEC 2009	JAN 2010	FEB 2010	MAR 2010	APR 2010	MAY 2010	JUN 2010	JUL 2010	AUG 2010	SEP 2010	TOTAL
PGC Rate FY 10	$6.8720	$6.8720	$6.8720	$6.8720	$6.8720	$7.7174	$7.9992	$7.9992	$7.2493	$6.9993	$6.9993	$6.9993	
Sept 10 PGC Rate	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	$6.9993	
PGC Rate Variance	$0.1273	$0.1273	$0.1273	$0.1273	$0.1273	($0.7181)	($0.9999)	($0.9999)	($0.2500)	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	627	574	1,041	1,789	1,548	1,276	689	422	226	167	139	182	8,680
Revenue Variance	$80	$73	$133	$228	$197	($916)	($689)	($422)	($57)	$0	$0	$0	($1,373)

UGI Central Penn Gas, Inc.
Historic Period - 12 Months Ended September 30, 2010
($ in Thousands)

Adjustment for USP

Cost of Goods Adjustment	
Original COG Revenue (Residential)	$32,022
Less USP Revenue	($651)
Adjusted COG Revenue(Residential)	$31,370
Base Revenue Adjustment	
Annualized Historic Year USP Rate	$0.0536
Rate R Volumes (excl CAP)-MDTH	5,227
Adjusted Revenue for USP	$280
Net USP Revenue Adjustment	($371)

UGI Central Penn Gas, Inc.

Rate NNS Calculation:

Assumptions:

1. Customer deliveries are assumed at a level daily rate.
2. The average storage trip cost of Columbia FSS, Dominion GSS, Texas Eastern SS-1, Transco GSS, Transco WSS, Transco LG-A, Wharton, and Tioga/Meeker are used as a proxy.
3. A $4.50/Mcf gas cost assumption is used for the calculation of fuel costs associated with the storage trip.
4. A 75% load reduction on weekends is assumed, based on fiscal year 2010 actual usage.

Calculation:

WD = weekday use
WE = weekend use

(5 x WD + 2 x WE)/7 = average
WD = 4 x WE
(5 x 4 x WE + 2 x WE)/7 = average
(22 x WE)/7 = average

Therefore:

Imbalance = 5 x (WD – average) + 2 x (average – WE)
= (60/22) x average

Unit Cost Calculation
[(60/22 x average)/(7 x average)] x storage trip cost
= per unit cost =
(60/22) x (1/7) x storage trip cost =
0.39 x storage trip cost =
0.39 x $0.210/Mcf = $0.082/Mcf

Per Unit of Demand Calculation
$0.082/Mcf x 20 = $1.64/Mcfd

CPG Exhibit PJS-6

UGI Central Penn Gas, Inc.

Rate MBS Calculation:

Assumptions:

1. The average capacity charge of Columbia FSS, Dominion GSS, Texas Eastern SS-1, Transco GSS, Transco WSS, Wharton, and Tioga/Meeker are used as a proxy.
2. Wharton and Tioga/Meeker rate set at settlement price of $0.259/dth of MSQ per year.
3. Total projected transportation throughput is based on fiscal year 2010 actual usage.
4. System average transportation load factor is based on fiscal year 2010 actual usage divided by the sum of MDQ Firm and Daily Interruptible Quantity.
5. Storage use will vary with load factor, that is, 100% load factor uses 0% storage.

Calculation:

Average capacity charge for storage: $0.2281/Dth

Average capacity charge for storage: $0.2345/Mcf
(@ 1.028 Btu/cf)

Total projected transportation throughput: 12,679,671 Mcf

System average transportation load factor: 34%

Anticipated average monthly imbalance percentage: 1.7%
(utilizing UGI Utilities imbalance percentage as proxy)

Rate allocation formula by Load Factor: [($0.2345/0.34) – ($0.2345/0.34 x Load Factor)] x 0.017

Accordingly:

Rate Schedule	Load Factor	MBS Rate
Rate DS	25%	.009
Rate LFD	53%	.006
Rate XD	86%	.002

CPG STATEMENT NO. 5 – DAVID E. LAHOFF

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
	:	
v.	:	Docket No. R-2010-2214415
	:	
UGI CENTRAL PENN GAS, INC.	:	
	:	

DIRECT TESTIMONY
OF DAVID E. LAHOFF

CPG Statement No. 5

Proposed Tariff Changes

Energy Efficiency & Conservation Rider

Conservation Development Rider

Natural Gas Vehicle Development Rider

Natural Gas Vehicle Service Rate

Forfeited Discounts

I. INTRODUCTION

Q. Please state your full name and business address

A. My name is David E. Lahoff. My current business address is 2525 N. 12th Street, Suite 360, Reading, Pennsylvania 19612.

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

A. I am employed by UGI Utilities, Inc. ("UGI"). I am Manager, Rates for UGI.

Q. What is your educational background and work experience?

A. I received an undergraduate degree in business from The Pennsylvania State University and a Masters Degree in Business Administration from the University of Connecticut.

Q. Please describe your professional experience.

A. In 2002, I was named Manager, Special Projects for UGI. In 2003, I became Manager, Customer Accounting Services for UGI, where my responsibilities included the administration of all Customer Accounting functions including Customer Contact Centers, Credit & Collections, Central Customer Accounting, Central Dispatch, Customer Outreach and Regulatory Compliance. Beginning in 2007, I returned to the position of Manager, Special Projects. My primary assignment in that position was Project Manager for the CONCISE project, a system conversion project involving the consolidation of all UGI and PNG customer account and work order information into a common system. Following the completion of that project, I was named Manager, Rates, responsible for the management of rates across all UGI utility operating companies. Prior to joining UGI Utilities in 2002, I held a number of operational management positions in the Retail Industry.

Q. Please describe the purpose of your testimony.

A. I will address the following issues in my testimony: (1) a summary of the proposed changes to the tariff rules and regulations included in the proposed UGI Central Penn Gas Tariff Pa. P.U.C. No. 4 ("Tariff No. 4"), and changes to the Choice Supplier Tariff, which is being incorporated into Tariff No. 4 as found in CPG Exhibit F (Part II); (2) how CPG is proposing to recover the costs of implementing its three-year Energy Efficiency and Conservation Plan ("EE&C Plan") through the Energy Efficiency and Conservation Rider ("EEC Rider") (Part III); (3) CPG's proposal to maintain revenue stability via the Conservation Development Rider ("CD Rider") as a result of customers taking advantage of the various EE&C programs and measures (Part IV); (4) CPG's proposal to recover the costs associated with its three-year Natural Gas Vehicle Pilot Program ("NGVP Program") through the Natural Gas Vehicle Pilot Rider ("NGVP Rider") (Part V); (5) an explanation of the Natural Gas Vehicle Service (Part VI); and (6) an explanation for the adjustments to forfeited discount revenue for the future test year (Part VII).

Q. Mr. Lahoff, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following Exhibits: CPG Exhibit F - Proposed UGI Central Penn Gas Tariff Pa. P.U.C. No. 4 (“Tariff No. 4”), replacing the current Gas Pa. P.U.C. No. 3 (“Tariff No. 3”); CPG Exhibit DEL-1, showing the annual costs and deemed savings of the Company’s EE&C Plan; CPG Exhibit DEL-2, showing the calculation of the proposed EEC Rider; CPG Exhibit DEL-3 showing the calculation of the proposed CD Rider and Exhibit CPG DEL-4, showing the calculation of the NGVP Rider. I am also sponsoring certain responses to the Commission’s filing requirements. Each response identifies the witness sponsoring it.

II. <u>PROPOSED TARIFF CHANGES</u>

Q. Is there a comprehensive list of changes that summarizes all the proposed tariff changes?

A. Yes. This can be found in the “LIST OF CHANGES” section of CPG Exhibit F - Proposed UGI Central Penn Gas Tariff Pa. P.U.C. No. 4. Mr. Szykman addresses the proposed CPG rate design changes in his direct testimony (CPG Statement No. 4). I will provide a summary of the proposed changes to the Tariff rules and regulations.

Q. Would you briefly describe the contents of the LIST OF CHANGES section of CPG Exhibit F?

A. The LIST OF CHANGES contains a comprehensive summary of the Company’s proposed rules and rate changes, identifying by page number(s) the proposed change in the new tariff, the relevant page number(s) of the current Tariff No. 3 that are being revised by the change, and the reason for the change.

Q. Mr. Lahoff, please explain why the Company has not provided a black-line version of the proposed Tariff No. 4.

A. As explained below, and in the direct testimony of Mr. Szykman, the Company is proposing substantial changes to its existing tariff in order to harmonize CPG's tariff with those previously approved by the Commission for UGI Utilities, Inc. – Gas Division ("UGI") and UGI Penn Natural Gas, Inc. ("PNG"). Given the significant number of proposed changes, the Company does not believe that a black-line version of the proposed Tariff No. 4 would be beneficial. Rather, the Company believes that the Digest set forth in the LIST OF CHANGES section of CPG Exhibit F will provide a useful overview of the proposed rules and rate changes.

Q. Why does CPG propose to make these changes?

A. CPG proposes to make these changes to its tariff for several reasons. First, CPG is pursuing a "best practices" model based upon a review of the existing, Commission-approved tariffs of UGI and PNG. Until recently, each of the three companies had different operating methods for similar situations. However, on August 27, 2009, the Commission approved a Joint Petition for Settlement in PNG's last base rate case at Docket No. R-2008-2079660 that, among other things, standardized PNG's rate schedules and tariff rules and regulations to be consistent with those currently found in UGI's tariff. I note that the parties to PNG's last base rate did not oppose and generally supported the standardization of PNG's and UGI's tariffs. Here, CPG seeks to harmonize its rate schedules and tariff rules and regulations with those currently found in the Commission-approved tariffs for UGI and PNG. The standardization of the three tariffs will facilitate tariff administration and create common rate schedules across the operating companies. The Company also believes that the standardization of the three tariffs should make it easier for suppliers to provide service and should foster greater competitive choices for customers.

Second, as part of its application to acquire PPL Gas Utilities Corporation, now CPG, UGI made a commitment to "investigate the feasibility and desirability of adopting uniform rules and protocols for all of its gas businesses to facilitate participation by natural gas suppliers in the competitive retail market through a greater geographic area with the potential to serve a greater number of customers." Consistent with this commitment, UGI initiated a collaborative process with interested stakeholders and conducted meetings to consider and receive input on tariff changes and other practices to facilitate retail choice. Several of the tariff provisions proposed are reflective of the concerns and suggestions UGI has heard through the collaborative process.

Q. Please describe how CPG's Proposed Tariff No. 4 will be consistent with the tariffs currently in effect at UGI and PNG.

A. One major change proposed in Tariff No. 4 is that it will be reorganized from its current format to be consistent with the format used by UGI and PNG. As shown in the Table of Contents on page 3 of Tariff No. 4, there will be a new separate "Definitions" section that will follow the Description of Territory. The "Rules and Regulations," section, which is currently at the end of Tariff No. 3, will be relocated to immediately follow the "Definitions" section in the proposed Tariff. The various surcharges and riders will be incorporated into the relocated "Rules and Regulations" section. The "Rate Schedules" section will then follow the "Rules and Regulations" section. Another significant change is that CPG's Choice Supplier Tariff, Tariff No. 3-S, will be incorporated into Tariff No. 4 as Section B – The Choice Supplier Tariff. This reorganization will provide Tariff No. 4 with a format similar to that used in the tariffs of UGI and PNG. The Company also believes that the standardization of the three tariffs will make it easier for suppliers to provide service and will foster greater competitive choices for customers.

Q. Please describe the major changes to the "Definitions" section of CPG's Tariff.

A. In this section, CPG will add definitions for certain terms such as Supplier of Last Resort, Critical Day, and others to define what these terms mean in order to provide clarity to customers.

Q. Please describe the major changes to the "Rules and Regulations" section.

A. Changes in this section have been made to implement "best practices" and to revise certain Rules and Regulations in a manner that can be consistently applied with a goal of creating commonality for all UGI, PNG, and CPG business practices. As previously mentioned, the various surcharges and riders will now be included in the Rules and Regulations as opposed to stand alone sections in the tariff. In addition, various changes will be made to the Rules and Regulations to reflect a restructuring of tariff terms to standardize and simplify presentation. CPG believes that these modifications will simplify tariff administration.

Q. Please describe the revisions to the Company's transportation rules.

A. Under Rule 16, CPG has, in large part, adopted the General Terms for Delivery Service for Rates DS, LFD, XD and IS contained in the existing tariffs for UGI and PNG. As explained in the direct testimony of Mr. Szykman (CPG Statement No. 4), CPG's goal is to modify the transportation service offerings in a manner that promotes the expanded use of transportation services on the CPG system by all customers, while, at the same time, providing the appropriate mechanisms to maintain appropriate distribution system management and reliability through reasonable cost allocations, operational controls, and procedures. One primary method to manage system reliability is through the concept of Critical versus Non-Critical days. This concept arose out of the Supplier Collaborative discussed above. On Critical days, charges for imbalances are increased substantially to overcome financial incentives for natural gas suppliers and customers to price arbitrage or place system reliability at risk.

Q. Please provide an overview of the proposed new rate structures.

A. Mr. Szykman addresses the proposed CPG rate design changes in his direct testimony (CPG Statement No. 4). As noted earlier, the proposed CPG rate design will be largely based on the Commission-approved rate designs that are currently in effect at UGI and PNG. This structure consists of general service rates for both residential and non-residential customers (Rates R and N, respectively), as well as Choice rates for these customers (Rate RT and NT). The new structure also includes three levels of firm commercial and industrial transportation rates (Rates DS, LFD and XD), as well as a rate for interruptible transportation service (Rate IS). In addition to these basic rate schedules, the new rate structure includes rates specific to: gas lights, gas air conditioning, balancing services and rider rates for retail and standby service, and service associated with natural gas vehicles.

An additional change in the rate design is the unit of measurement shown on customers' bills. Currently, CPG measures gas used by customers on a volumetric (or cubic foot) basis. CPG multiplies the volumetric readings registered by customer meters by a BTU (British Thermal Unit) factor to calculate the number of dekatherms consumed and generates a bill based on dekatherms as the unit of measurement. This BTU factor is adjusted based on the system average BTU value. The rate customers pay is expressed in terms of BTUs and customers see their BTU usage on their bills.

As part of this filing, CPG is proposing to modify this procedure. CPG will continue to measure customers' usage on a volumetric (or cubic foot) basis and continue to apply a BTU factor to calculate the number of dekatherms consumed by the customers. However, instead of presenting the bill to customers on a BTU basis, the bill will be presented based on a volumetric unit of measurement that has been corrected to standard conditions (either up or down) to account for the actual BTU content of the gas consumed. The rate customers pay is expressed in terms of cubic feet and customers see a volumetric usage on their bills based on this correction to standard conditions. There is no impact to the amount of the bill as a result of this change in the unit of measurement as presented on the bill. The BTU factor would be adjusted monthly, either up or down, based on a rolling 12 month system average to account for fluctuations in the heating value of the gas consumed in order to bill at standard conditions. For the purposes of this filing, standard conditions will be based on a BTU factor of 1.029, which is the rolling 12 month system average ending November, 2010. The Pro Forma consumption shown on CPG Exhibit E utilizes this 1.029 BTU value to convert the consumption to Mcf. In addition, CPG Exhibit E also contains a schedule showing proposed rates on a dekatherm basis for comparative purposes. These proposed rates per dekatherm will be used for billing purposes during the transition period as described below.

Q. How is CPG proposing to bill customers during the period it is transitioning from a dekatherm to volumetric unit of measurement?

A CPG proposes to continue to bill customers on a dekatherm basis during the period from when the new rates are approved by the Commission until the end of the following billing month. For example, If new rates become effective October 15th, the dekatherm billing basis will expire November 30th and be replaced with the new volumetric basis on December 1. During the period from October 15th through November 30th, customer bills will be presented still on a dekatherm basis and the rate per dekatherm that will be used for billing purposes will be the rate per dekatherm equivalent of the approved rates.

Q. Why is CPG proposing this change in the unit of measurement?

A. CPG is proposing this change in order to establish consistency in unit of measurement for billing purposes with the other UGI gas utility businesses. Establishing this consistency will facilitate the standardization in a number of areas including: financial reporting, tariff administration, customer service, gas supply management, and administration of Gas Choice across the UGI gas divisions.

Q. Is CPG proposing any changes to Rider C – Universal Service Program ("USP")?

A. The Company is not proposing any changes to the USP Rider. The Company's proof of revenue in this filing reflects annualized USP revenues that are equal to annualized USP expenses in accordance with the reconcilable nature of the Rider.

Q. Are there any changes proposed to Rider D – Merchant Function Charge ("MFC")?

A. The Company is not proposing any conceptual changes to the MFC Rider. The Company is updating the percentages of the MFC to reflect the actual uncollectible expense experienced by the Company during the most recent five years. This five year average method is consistent with the approach used in CPG's last base rate case and is also consistent with the adjustment made for uncollectible expenses in this base rate filing. Based on this updated data, the MFC for the residential class will decrease from 2.6% to 2.26%. The MFC for the commercial class will be unchanged at 0.14%.

Q. Please summarize the proposed changes to the Choice Supplier Tariff.

A. To promote Choice on its system, CPG has, in large part, adopted the Choice Supplier Tariff used by UGI, which was also adopted by PNG in its last base rate case at Docket No. R-2008-2079660. Currently, CPG's Choice program is relatively static with approximately 1,000 Choice customers, having added only 300 customers in the past 12 months. UGI, on the other hand, has an active choice program with several natural gas suppliers serving approximately 17,765 Choice customers. In contrast to CPG, UGI has added over 6,000 customers during the past 12 months. In addition, prior to adopting the UGI Choice Supplier

Tariff in its last base rate case, PNG had no Choice customers on its system. Since transitioning to the UGI Choice Supplier Tariff, PNG's Choice program has increased substantially, growing from zero customers to over 3,200 Choice customers in the past 12 months. CPG believes that adopting the Choice Supplier Tariff currently in place for UGI and PNG should promote Choice on the CPG system.

Q. Are there any other major changes to CPG's Tariff.

A. Yes. One important change is the proposed elimination of Rate Schedule S. CPG has owned certain natural gas interstate storage facilities in the Tioga West, Meeker and Wharton Storage Fields ("Storage Facilities") located in Potter, Cameron and Tioga counties in Pennsylvania. Rate Schedule S is a service available pursuant to executed service agreements wherein CPG agrees to receive and store gas at the Storage Facilities and then redeliver gas to the customer at specified delivery points at which the facilities of the Company and the customer connect.

On November 19, 2009, UGI Storage Company ("UGI Storage") filed an application at FERC at Docket No. CP10-23-000 for a certificate of public convenience and necessity to acquire the Storage Facilities from CPG, and to own and operate them in interstate commerce. In conjunction with this action, CPG filed a Petition with the Commission at Docket No. P-2009-2145774 seeking approval to reduce its base rates upon FERC approval of the transfer of the Storage Facilities. On September 28, 2010, the Commission approved a Proposed Stipulation to Resolve All Outstanding Issues resulting from CPG's Petition, and ordered CPG to file a compliance tariff supplement implementing the terms of the Stipulation as modified effective on one-day's notice following FERC's issuance of a certificate of public convenience authorizing UGI Storage to acquire the Storage Facilities. On October 21, 2010, FERC issued an Order approving, among other things, UGI Storage's application for approval to acquire the Storage Facilities from CPG.

As a result, the Storage Facilities will be transferred from CPG to UGI Storage and, consequently, CGP will no longer provide the services previously provided under Rate Schedule S. Therefore, consistent with the Commission's Order approving CPG's Petition, CPG herein proposes to eliminate Rate Schedule S effective following FERC's issuance of a certificate of public convenience authorizing UGI Storage to acquire the Storage Facilities and to own, operate and maintain them in interstate commerce, UGI Storage Company's acceptance of the certificate, and the actual transfer of the Storage Facilities from CPG to UGI Storage, which is currently anticipated to occur on April 1, 2011.

Although the rate will not actually disappear from the tariff until the Commission has approved the tariff supplement at the conclusion of this base rate case, the language in the currently effective tariff renders Rate Schedule S unavailable upon transfer of the storage facilities. Given the timing of the expected transfer, CPG intends to cease providing service under Rate Schedule S at the end of the current withdrawal period, April 1, 2011.

III. <u>EEC RIDER</u>

Q. Please explain why CPG is proposing an EEC Rider.

A. In the Joint Petition for Settlement of its last base rate case at Docket No. R-2008-2079675, CPG committed to, among other things, meet with interested parties to design an Energy Efficiency and Conservation Plan ("EECP") to coordinate with the energy efficiency and conservation requirements of Act 129. Consistent with this commitment, CPG met with a variety of stakeholders in the context of various electric distribution companies' Act 129 plans and has participated in a variety of Act 129 and non-Act 129 energy efficiency forums sponsored by the Commission and other entities. As a result, CPG has developed a new energy efficiency and conservation plan. The details of CPG's proposed EECP, including the development of the costs associated with the EECP, are explained in the direct testimonies of Mr. Paul Raab (CPG Statement No. 9,) and Mr. Brian Fitzpatrick (CPG Statement No. 10). I will explain how CPG proposes to recover the costs associated with the implementation and administration of the EECP through the proposed EEC Rider.

Q. What is CPG's projection of the annual costs for its EECP?

A. The projected annual costs for the Company's EECP are approximately $2.8 million, or approximately 2% of the Company's sales revenue of $128 million in fiscal 2010, which equates to a total budget of approximately $8.4 million over the life of the Plan. This budget includes the Company's annual spending target on the EE&C programs and measures of approximately $2.56 million, plus an additional $256,000 per year to cover the Company's annual internal administrative costs incurred to implement and administer the EECP each year. CPG Exhibit DEL-1 shows the projected annual costs for each program for each year of the Plan as supplied by Mr. Fitzpatrick.

Q. How was the Company's spending target on the EECP programs and measures calculated?

A. The Company arrived at its spending target based on developing rebates and incentives for the various plan components that would be viewed as meaningful by the customer and designed to encourage strong participation levels. In addition, while natural gas distribution companies are not subject to Act 129, CPG also relied on the 2% spending cap in Act 129 in the establishment of the overall budget for the program.

Q. How is the total expenditure target allocated among the customer classes?

A. Of the $8.4 million budget, CPG budgets $6.6 million, plus or minus $0.5 million, over the three years for programs that benefit the residential customer class, and $1.8 million, plus or minus $0.5 million, per year for programs that benefit the non-residential customer class. These program budgets include internal administrative costs of $256,000 per year which are allocated to the classes based on their portion of the total direct EECP program costs.

Q. Did the Company propose a limit on annual expenditures for its EECP programs?

A. No. CPG anticipates that it will take some time to fully implement the individual programs following Commission approval of CPG's EECP. Therefore, spending in the first year of the Plan may be less than the projected $2.8 million, while spending in subsequent years may be greater. The total spending over the three years on the EE&C programs and measures will not exceed the Company's expenditure target of $8.4 million.

Q. Please describe the rate mechanism CPG is proposing to use to recover the development and implementation costs of its EECP.

A. CPG proposes to recover the costs of its EECP through the reconcilable Energy Efficiency and Conservation Rider ("EEC Rider") under Section 1307 of the Public Utility Code. Because CPG's EECP will benefit both shopping and non-shopping customers, the Company has designed its cost recovery mechanism to be applicable to both supplier of last resort and choice customers. In this regard, CPG proposes that the cost recovery mechanism be included in the distribution charges for each customer class rather than appear as a separate line item on customers' bills. The *pro forma* tariff pages to implement the EEC Rider are included in Tariff No. 4. The tariff language provides a description of the cost recovery method, the formula for calculating the charge and the charges specific to each rate class. CPG Exhibit DEL-2 shows the calculation of the proposed annual EEC Rider.

Q. Please describe how CPG proposes to set the annual rates under the EEC Rider?

A. The EEC Rider was designed to capture actual yearly expenditures. Although the Company anticipates expenditures to "ramp up" for nearly half of its EE&C programs, it does not project the difference between the expenditures in the first year of the Plan and the expenditures in the last year of the Plan to be significant. Therefore, distribution of cost recovery should be relatively even over the term of the Plan.

Q. How many customer classes will be reflected in its annual cost recovery mechanism?

A. The Company proposes to separately calculate the applicable EE&C costs for two general customer classes on its system: (1) residential; and (2) non-residential customers served under rates N, NT, DS and LFD. The residential class includes low-income customers and customers served under Rate Schedules R and RT.

Q. What is CPG’s overall approach for determining which customer class is responsible to pay for the programs in the EECP?

A. Act 129 and the Commission require that the EE&C programs approved by the Commission be supported by the same customer classes that will receive the direct energy and conservation benefits. Following that guidance, under the

Company's Plan, the cost of EE&C programs that target specific rate classes are directly assigned to those classes for purposes of developing the recovery charge.

Q. What is the recovery period and when will it begin and expire?

A. The Company proposes that the EEC Rider become effective coincident with the effective date of the first quarterly Purchased Gas Cost Adjustment filing following the Commission's approval of CPG's base rate filing. The EEC Rider will apply to all usage on and after that date, through and until the last day of the respective month in year four. As stated above, CPG is only proposing a three-year period for this Plan. However, since year three of the EECP may result in over or under collections of expenses, the rate recovery mechanism will continue through year four so that the Company may fully recover any under collection or refund any over collection incurred during year three. Also, at the end of the year four reconciliation, a small amount may remain on the books. If this were to occur, the Company plans to roll this amount into the subsequent annual Purchased Gas Cost filing.

Q. Will the Company file for reconciliation each year?

A. The Company proposes to adjust the EEC Rider for actual program expenses and revenues experienced each year, (October 1 through September 30), ("Plan Year"). The Company will treat the estimated $256,000 in internal administrative costs as a fixed amount for the purposes of the reconciliation. Each year, on

November 30th, the Company will submit a filing to become effective on one day's notice to reconcile previous Plan Year revenues and expenses and adjust the EEC Rider. In addition, the Company reserves the right to make an interim filing (also to become effective on one day's notice) to adjust the EEC Rider if it becomes evident that the over or under recovery is significantly deviating from expected activity. The net over or under collections will be based on the difference between the actual EEC Rider revenues received and the actual EECP costs incurred. The calculation of the EEC Rider for each Plan Year will include the actual over or under collections for the previous Plan Year. The first such November 30th filing will be made in 2012.

IV. CD RIDER

Q. Please describe the rate mechanism CPG is proposing to use to recover the reduced revenues associated with the reduced energy consumption.

A. CPG proposes to recover the lost revenues associated with the implementation of its EECP through a reconcilable charge, the Conservation Development Rider ("CD Rider"),that will be billed to all firm customers excluding its largest Industrial customers served under rate XD. CPG proposes that the CD Rider be applied to the distribution charges for each customer class rather than appear as a separate line item on the customers' bills. The *pro forma* tariff pages to implement this revenue recovery mechanism are included in CPG Exhibit F, the Proposed UGI Central Penn Gas Tariff Pa. P.U.C. No. 4. The tariff language provides a general description of the cost recovery method, the formula for calculating the charge, and the charges specific to each rate class. CPG Exhibit DEL-3 shows the calculation of the proposed annual CD Rider.

Q. What is CPG's overall approach for determining which customer class is responsible to pay for the lost revenues associated with the EECP?

A. As described above, the lost revenues per customer class is determined by the deemed energy savings for the customer class.

Q. Why is the Company proposing to recover lost revenues through a reconcilable rate?

A. The Company believes that it is reasonable to offer energy efficiency programs to customers and also reasonable that the Company not be financially harmed by offering such programs. This approach is consistent with the American Recovery and Reinvestment Act of 2009 ("ARRA") which requires state regulatory agencies to consider policies that allow utilities to recover their costs, and at the same time encourage greater conservation. The relevant portion of the ARRA states:

> *The applicable State regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the State regulatory authority has rulemaking authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.*

One way the Commission is able to support the concept contained in the ARRA is to approve CPG's CD Rider, which will protect CPG from financial harm for encouraging greater energy conservation.

Q. What is the recovery period and when will it begin and expire?

A. The Company proposes to recover lost revenues associated with the implementation of the EECP programs through the CD Rider. The Company proposes to initially set the rate for the CD Rider at zero and to defer any recovery for 12 months. Following that period, the Company will submit a filing each year to become effective on one day's notice in order to recover lost revenues. Such lost revenues shall be calculated based on the accumulated deemed savings of customers installing EECP measures. The CD Rider will operate in this fashion each year until an order is entered by the Commission in CPG's next base rate case and CPG's resulting compliance filing becomes effective. This proposal is designed to capture the continued savings resulting from the Plan. Even though CPG is only proposing a three-year period for this Plan, customers will continue to conserve energy and save money beyond this time period, and likewise the Company will continue to experience revenue losses. If the EECP is scheduled to continue after the conclusion of CPG's next base rate case, the CD Rider would be set to zero after an order is entered by the Commission in CPG's next base rate case and CPG's resulting compliance filing becomes effective. The CD Rider would remain at zero until the next reconciliation at which time any additional deemed savings experienced would be reflected as an adjustment to the CD Rider. The schedule in CPG Exhibit DEL-3 shows that, due to the "ramp-up" effect, customers will experience greater energy savings in later years of the Plan as compared to the earlier years of the Plan, since more conservation measures will have been installed. The Company anticipates that the revenue losses to be experienced in Years Four and beyond should be approximate to or slightly greater than the revenue losses incurred during year three because all of the planned measures will have been fully implemented by the end of year three.

Q. Will the Company file for reconciliation each year?

A. Yes. CPG proposes to adjust the CD Rider each year on a parallel track with the EEC Rider. Each year, on November 30th, the Company will submit a filing to become effective on one day's notice in order to reconcile previous Plan Year (October 1 through September 30) revenues received and deemed savings incurred and adjust the CD Rider, although the Company reserves the right to make an interim filing (also to become effective on one day's notice) to adjust the CD Rider if it becomes evident that the over or under recovery is significantly deviating from expected activity. The net over or under collections will be based on the difference between the actual CD Rider revenues received and the actual EECP plan deemed savings incurred. The first such November 30th filing will be made in 2012.

V. NGVP RIDER

Q: Why is CPG proposing the NGVP Rider?

A: The Natural Gas Vehicle Pilot Program ("NGVP Program") is intended to promote the build-out of natural gas vehicles from a demand development perspective. From an environmental standpoint, Natural Gas Vehicles (NGVs) produce approximately 25 to 30% less CO_2 emissions and 70 to 90% less NO_x, VOC, and particulate matter emissions as compared to standard fueled gasoline/diesel oil counterparts. From an energy security standpoint, 86% of the natural gas consumed in the U.S. is domestically produced (98% if you include Canadian imports). In addition, U.S. natural gas consumption will be even more domestically sourced with expanded shale development. Marcellus shale production in PA, and in other states, has increased the U.S. natural gas reserves to a 100 plus year supply. As a result of the abundance of natural gas supplies and declining prices in the $5 per MMBtu range, NGVs can and will help the U.S. reduce dependence on oil imports. In summary, there is a renewed interest in NGVs because there are new technologies for drilling shale gas, there is a heightened recognition of natural gas's smaller carbon footprint as compared to gasoline and diesel oil, and there have been advances in transportation-oriented natural gas technology.

Q: What is CPG's projection of the annual costs for the NGVP Program?

A: The NGV Program is a three-year program with a maximum total program expenditure of $1,030,000. This budget reflects the cost of grants that will be provided by CPG to qualified Commercial customer NGV projects to offset initial capital expenditures, including natural gas vehicle purchases, vehicle conversions, and/or natural gas vehicle fueling infrastructure. CPG Exhibit DEL-4 shows the projected annual costs for the NGVP Program.

Q: How was the spending target for the NGVP Program developed?

A: The spending target of $1,030,000 over three years was based on an estimate of five (5) projects in the CPG service territory and a maximum grant amount of $200,000 per project and internal administrative costs of $10,000 per year.

Q: How does CPG propose to recover the cost of the NGVP Program?

A: CPG proposes to recover the cost of the NGVP Program through the NGVP Rider. It will apply to all non-residential customers, except customers served under competitive rate schedules Rate IS or Rate XD, to cover the three-year funding of the pilot program. Customers served under Rate schedules IS and XD shall not be permitted to receive grants under the NGVP Program. The NGVP Rider shall be fully reconcilable. The *pro forma* tariff pages to implement this revenue recovery mechanism are included in Tariff No. 4. The tariff language provides a general description of the cost recovery method, the formula for calculating the charge and the rate classes that will be subject to the surcharge. CPG Exhibit DEL-4 shows the calculation of the proposed NGVP Rider.

Q. What is the recovery period and when will it begin and expire?

A. The Company proposes that the NGVP Rider become effective coincident with the effective date of the first quarterly Purchased Gas Cost Adjustment filing following Commission approval of proposed base rates. The Company proposes that the NGVP Rider apply to all usage on and after that date, through and until the last day of the respective month in year four. As stated above, CPG is only proposing a three-year period for this pilot program. However, since year three of the NGVP Plan may result in over or under collections of expenses, the rate recovery mechanism must continue through year four so that the Company may fully recover any under collection or refund any over collection incurred during Year Three. Also, at the end of the year four reconciliation, a small amount may remain on the books. If this were to occur, the Company plans to roll this amount into a subsequent Purchased Gas Cost filing.

Q. Will the Company file for reconciliation each year?

A. Yes. Each year, on November 30th, the Company will submit a filing to become effective on one day's notice in order to reconcile previous Plan Year (October 1 through September 30) revenues and expenses and adjust the NGVP Rider, although the Company reserves the right to make an interim filing (also to become effective on one day's notice) to adjust the NGVP Rider if it becomes evident that the over or under recovery is significantly deviating from expected activity. The net over or under collections will be based on the difference between the actual NGVP Rider revenues received and the actual NGVP Program costs incurred. The first such November 30th filing will be made in 2012.

VI. NGV SERVICE

Q: How does CPG propose to charge customers for gas distribution service associated with NGVs?

A: CPG proposes to charge customers for gas distribution service associated with NGVs under a new rate rider, NGV Service. This rate will be applicable to firm commercial and industrial customers only, excluding Rate XD, and applied as a rider on an existing rate to discount the distribution service associated with that rate for the portion of gas used for natural gas vehicles. For example, a Rate DS customer could elect service under NGV Rider. The gas used for natural gas vehicles will be billed at a lower, negotiated rate. The other gas used for heating, etc. will be billed at the normal Rate DS. The *pro forma* tariff pages to implement this rate rider are included in Tariff No. 4.

Q: Is there a maximum rate associated with NGV Service?

A: Yes. It is the maximum firm rate applicable at the customer's location.

Q: Why does the NGV Service Rate not apply to Rate IS or Rate XD?

A: Rate IS and Rate XD schedules already provide fully negotiable terms and flexibility needed to accomplish the same goals.

Q: Will a separate meter be required?

A: Yes, a separate meter will be required to separately bill the gas used for natural gas vehicles from that which is used for other purposes.

VII Forfeited Discounts

Q. Is the Company making an adjustment to forfeited discounts for the Future Test Year?

A Yes, consistent with CPG's approach to developing both the proposed Merchant Function Charge and the adjusted level of uncollectible expense, the Company used a five year average of forfeited discounts as a percentage of revenue to adjust revenue from budgeted levels of forfeited discounts (See CPG Exhibit A, Schedule D-5B). This approach mitigates any aberration in a single year due to a non-recurring event.

Q. Does this conclude your direct testimony?

A. Yes.

CPG EXHIBIT NOS. DEL-1 THROUGH DEL-4

UGI Central Penn Gas, Inc.
Energy Efficiency and Conservation Plan
Annual Costs and Deemed Mcf Savings by Customer Class

Residential Customer Class

Plan Program (Annual Costs)	Year 1	Year 2	Year 3	Total
High Efficiency New Homes Program	$ 137,335	$ 140,085	$ 142,835	$ 420,255
High Efficiency Heating Upgrade Program	$ 748,825	$ 762,440	$ 776,327	$ 2,287,592
High Efficiency Water Heater Upgrade Program	$ 699,600	$ 712,100	$ 725,100	$ 2,136,800
Residential Keystone Help Assistance Program	$ 322,832	$ 329,419	$ 336,018	$ 988,270
Energy Education Program	$ 50,000	$ 51,000	$ 52,020	$ 153,020
Plan Costs by Year */1*	$ 1,958,592	$ 1,995,044	$ 2,032,300	$ 5,985,937
Plan Program (Deemed savings)				
High Efficiency New Homes Program	3,203	3,273	3,344	9,819
High Efficiency Heating Upgrade Program	14,760	15,056	15,357	45,172
High Efficiency Water Heater Upgrade Program	17,459	17,802	18,159	53,419
Residential Keystone Help Assistance Program	3,128	3,191	3,254	9,573
Energy Education Program	-	-	-	-
Mcf Savings - Annual Target	38,550	39,322	40,113	117,984

C&I Customer Class

Plan Program (Annual Costs)	Year 1	Year 2	Year 3	Total
C&I Combined Heat and Power	$ 330,000	$ 336,600	$ 343,332	$ 1,009,932
C&I Custom	$ 271,408	$ 228,356	$ 184,368	$ 684,131
Plan Costs by Year */1*	$ 601,408	$ 564,956	$ 527,700	$ 1,694,063
Plan Program (Deemed savings)				
C&I Combined Heat and Power	7,644	7,644	7,644	22,932
C&I Custom	10,000	10,000	10,000	30,000
Mcf Savings - Annual Target	17,644	17,644	17,644	52,932

Footnotes

1 Plan costs by year do not include administrative costs

UGI Central Penn Gas, Inc.
Energy and Efficiencyand Conservation Plan
Development and Impact of Energy Efficiency and Conservation Rate
"EEC Rate"

Residential Customer Class

Plan Year	Year 1	Year 2	Year 3
Program Cost - Residential	$ 1,958,592	$ 1,995,044	$ 2,032,300
Administrative Costs /1	$ 199,531	$ 199,531	$ 199,531
Total Costs - Residential	$ 2,158,123	$ 2,194,575	$ 2,231,831
Projected Residential Usage (Mcf)	5,014,914	4,976,364	4,937,043
EEC Rate ($/Mcf)	$ 0.4303	$ 0.4410	$ 0.4521

C&I Customer Class /2

Plan Year	Year 1	Year 2	Year 3
Program Cost - C&I	$ 601,408	$ 564,956	$ 527,700
Administrative Costs - C&I	$ 56,469	$ 56,469	$ 56,469
Total Costs - C&I	$ 657,877	$ 621,425	$ 584,169
Projected C&I Usage (Mcf)/3	8,794,812	8,777,168	8,759,524
EEC Rate ($/Mcf)	$ 0.0748	$ 0.0708	$ 0.0667

Footnotes

1 Administrative costs are allocated between residential and C&I based on their proportion of total program costs

2 C&I Customer Class for EEC program includes rates N,NT,DS and LFD

3 Projected C&I usage excludes rate XD

UGI Central Penn Gas, Inc.
Energy Efficiency and Conservation Plan
Development and Impact of Conservation Development Rate
"CD Rate"

Residential Customer Class

Plan Year	Year 1	Year 2	Year 3	Year 4
Cumulative Deemed Savings in Mcf	-	38,550	77,871	117,984
Distribution Rate (proposed)	$ 5.62	$ 5.62	$ 5.62	$ 5.62
Lost Revenue (based on the previous years deemed savings)	$ -	$ 216,642	$ 437,621	$ 663,048
Projected Residential Usage (Mcf)	5,014,914	4,976,364	4,937,043	4,896,930
CD Rate ($/Mcf)	$ -	$ 0.0435	$ 0.0886	$ 0.1354

C&I Customer Class /1

Plan Year	Year 1	Year 2	Year 3	Year 4
Cumulative Deemed Savings in Mcf	-	17,644	35,288	52,932
Distribution Rate (proposed) /2	$ 2.24	$ 2.24	$ 2.24	$ 2.24
Lost Revenue (based on the previous years deemed savings)	$ -	$ 39,486	$ 78,972	$ 118,457
Projected C&I Usage (Mcf) /2	8,794,812	8,777,168	8,759,524	8,741,880
CD Rate ($/Mcf)	$ -	$ 0.004	$ 0.009	$ 0.014

Footnote

1 C&I Customer Class for EEC program includes rates N,NT,DS and LFD
2 C&I distribution rate is a blended average of the proposed distribution rates for rates N,NT.DS and LFD
3 Projected C&I usage excludes rate XD

UGI Central Penn Gas, Inc.
Natural Gas Vehicle
Development Program - NGVP
Development of NGVP Surcharge

	C&I Customer Class /1		
Plan Year	**Year 1**	**Year 2**	**Year 3**
Natural Gas Vehicle Development Grant Amounts	$ 200,000	$ 400,000	$ 400,000
Administrative Costs	$ 10,000	$ 10,000	$ 10,000
Total Costs	$ 210,000	$ 410,000	$ 410,000
Projected C&I Usage (Mcf) /2	8,794,812	8,759,524	8,741,880
NGVP Rate ($/Mcf)	$ 0.0239	$ 0.0457	$ 0.0458

Footnotes

1 C&I Customer Class for EEC program includes rates N,NT,DS and LFD

2 Projected C&I usage excludes rate XD

CPG STATEMENT NO. 6 – JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
	:	
v.	:	Docket No. R-2010- 2214415
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UGI CENTRAL PENN GAS, INC.	:	

DIRECT TESTIMONY
OF JOHN F. WIEDMAYER C.D.P.

CPG Statement No. 6

Depreciation

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2010-2214415

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm?

A. Yes. I am associated with the firm of Gannett Fleming, Inc.

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

A. I have been associated with the firm since I graduated from college in June, 1986.

Q. What is your position with the firm?

A. I am Project Manager, Depreciation Studies of Gannett Fleming's Valuation and Rate Division.

Q. What is your educational background?

A. I have Bachelor of Arts degree in Engineering from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals (SDP). In 2005, I served as President of the Society of Depreciation Professionals and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Engineer. I held that position from June, 1986 through December, 1995. In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to my present position as Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming I have assisted in the preparation of numerous depreciation studies for utility companies in various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Telus, and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Penelec, Metropolitan Edison, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: UGI Utilities, North Penn Gas, PFG Gas, UGI-CPG, Equitable Gas, Centra Gas Alberta, Questar Gas, Dominion East Ohio, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission and the Pennsylvania Public Utility Commission.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life

Analysis Using Simulation" and "Managing a Depreciation Study." In 2000, I became an instructor at the Society of Depreciation Professionals annual conference lecturing on "Salvage Concepts," "Depreciation Models," and "Data Requirements for a Depreciation Study."

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been retained by UGI Central Penn Gas, Inc. ("UGI-CPG") as a depreciation consultant. UGI-CPG retained me to determine the book depreciation reserve as of September 30, 2011, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI-CPG's depreciated original cost of gas plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2011.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI-CPG Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
I-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI-CPG?

A. Yes. I provided testimony on depreciation matters for the company in a prior base rate case at Docket No. R-2008-2079675. Prior to acquisition by UGI, our firm prepared exhibits for the most recent combined depreciation studies for PPL Gas at Docket Nos. R-00005277 and R-00061398. Prior to those rate filings, I prepared exhibits for the depreciation study in the combined rate proceeding for North Penn Gas Company and PFG Gas, Inc. at Docket No. R-00953524.

III. OUTLINE OF EXHIBITS C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: Exhibit C (Future) and Exhibit C (Historic). Exhibit C (Future) presents summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year. Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year.

Q. Does Exhibit C (Future) accurately portray the results of your depreciation study as of September 30, 2011?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study report, Exhibit C (Future).

A. The depreciation study report consists of three parts. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Methods Used in the Determination of Annual and Accrued Depreciation, presents detailed discussions of: (1) survivor curves; (2) methods of life analysis including an example of the retirement rate method; (3) group procedures for calculating annual and accrued depreciation; and (4) an explanation of the manner in which net salvage was incorporated in the calculations. Part III, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2011. Appendix A presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Appendix B presents the detailed depreciation calculations related to surviving original cost as of September 30, 2011. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Appendix B. Appendix C contains the net salvage amortization of experienced and estimated net salvage for the years 2006 through 2011.

Table 1, pages III-4 through III-6 of Exhibit C (Future), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2011, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages III-7 through III-9 of Exhibit C (Future), presents the bring forward to September 30, 2011, of the depreciation reserve as of September 30, 2010. Table 3, pages III-10 through III-12 of Exhibit C (Future), presents the calculation of the depreciation amounts for the future test year. Table 4, page III-13 of Exhibit C (Future), presents the experienced and estimated net salvage for fiscal years 2006 through 2011. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2006 through September 30, 2011.

Q. Please outline the contents of Exhibit C (Historic).

A. Exhibit C (Historic) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2010. The descriptions and explanations presented in Exhibit C (Future) are also applicable to the depreciation calculations presented in Exhibit C (Historic). The graphs and tables related to service life presented in Exhibit C (Future) also support the service life estimates used in Exhibit C (Historic), inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of September 30, 2010, are organized and presented in the same manner as those as of September 30, 2011.

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation".

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities and the exhaustion of natural resources.

In the study that I performed and which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner. These methods and procedures were used in the Company's most recent prior general rate proceeding at Docket No. R-2008-2079675 and are described in Part II of Exhibit C (Future).

For General Plant Accounts 391, 392, 393, 394, 395, 397 and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of gas plant to be included in rate base in this proceeding?

A. As of September 30, 2011, the original cost of gas plant that serves Pennsylvania customers is $347,163,480 as shown in column 3 of Table 1 on page III-6 of Exhibit C (Future). This amount includes $347,163,480 of gas plant in service and $0 for construction work in progress (CWIP). The original cost of gas plant shown in my testimony and in Exhibits C (Historic) and C (Future) excludes gas plant that serves Maryland customers. Approximately $1.9 million of gross gas plant ($1.4 of net gas plant) that serve customers in Frederick County, MD was excluded. Frederick County, MD is located on the Pennsylvania border south of Adams County, PA. UGI-CPG provides gas service to approximately 500 Maryland customers in Frederick County, MD.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI-CPG's accrued depreciation for ratemaking purposes as of September 30, 2011?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2011, to be $113,024,318.

Q. How did you determine UGI-CPG's allocated book depreciation reserve as of September 30, 2011?

A. The allocated book depreciation reserve as of September 30, 2011, is set forth in column 4 of Table 1 of Exhibit C (Future). Table 2 of Exhibit C (Future) is a bringforward of the book depreciation reserve as of September 30, 2010, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2010 through September 2011. The table sets forth, by plant account, the book reserve balances as of September 30, 2010, the estimated reserve activity, and the reserve balance as of September 30, 2011. The estimated reserve activity consists of depreciation accruals (column 3), projected retirements (column 4), projected salvage (column 5), projected cost of removal (column 6), and amortization of net salvage (column 7). Table 3 of Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account which is carried forward to column 3 of Table 2. The ratemaking book reserve as of September 30, 2010, by plant account, shown in column 2 of Table 2 was obtained from UGI-CPG's books and records.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2011.

A. The depreciation accruals for the twelve months ended September 30, 2011, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2010, to the projected average plant balance. The average balance for the twelve months ended September 30, 2011, is computed in columns 2 through 6 of Table 3 and is based on the projected additions and retirements in columns 3 and 4.

Q. With reference to Table 2, column 7, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2005 through September 30, 2010.

Q. With reference to Table 2, column 7, please explain the manner in which you projected the amortization of net salvage to be recorded during the twelve months ended September 30, 2011.

A. The amortization of net salvage for the twelve months ended September 30, 2011, is one-quarter of the annual average of the experienced net salvage for the period 2005 through 2010, plus three-quarters of the annual average of experienced and estimated net salvage for the period 2006 through 2010.

Q. Please explain the manner in which you projected retirements, salvage and removal costs that are shown in columns 4, 5 and 6 of Table 2.

A. Retirements were projected by plant account by applying the average retirement, as a percent of additions, for the five years 2006 through 2010, to the future test year additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the future test year for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal, as a percent of retirement amounts, for the five years 2006 through 2010, to the projected retirement amounts.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI-CPG's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $9,555,123 and consists of $8,477,933 of annual accruals to recover original cost and $1,077,190 of net salvage amortization. These amounts are set forth in column 7 of Table 1 in Exhibit C (Future).

Q. How did you determine the annual accruals of $8,477,933?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, service life characteristics are estimated for each depreciable group; that is, each plant account or subaccount is identified as having similar characteristics. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of: compiling historical data from records related to UGI-CPG's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI-CPG's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of UGI-CPG's gas plant?

A. The data consisted of the entries made by UGI-CPG to record gas plant transactions during the period 1951 through 2007. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve as plotted from the life table represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used in these interpretations. The results of the retirement rate analyses are presented in Appendix A of Exhibit C (Future).

Q. Please explain briefly what an "Iowa-type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania and the remaining 49 other states and have been for many years.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 35-R2 indicates an average service life of thirty-five years; a Right-skewed, or R, type curve (the mode occurs after average life for right modal curves); and a relatively low height, 2, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the company and observe representative portions of the plant. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1992 and remaining lives consistent with the equal life group procedure for plant installed in 1992 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth on Table 1 of Exhibit C (Historic) and Exhibit C (Future). The detailed tabulations of the depreciation calculations are presented in Appendix A of Exhibit C (Historic) and Appendix B of Exhibit C (Future).

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1992.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1992 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please describe briefly the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 392, 393, 394, 395, 397 and 398 include a very large number of units, but represent a very small percent of depreciable gas plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired per books when the age of the vintage reaches the amortization period.

VIII. <u>ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE</u>

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in Exhibit C (Future) using an account as an example.

A. I will use Account 376, Mains, to illustrate the manner in which the study was conducted. Account 376 represents 47 percent of the total depreciable plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2007. These data have been coded in the course of UGI-CPG's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes primarily plastic and steel mains, although some cast iron mains are still in service. The Iowa 60-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The previous survivor curve estimate was the Iowa 52-L2 survivor curve. The Iowa 60-R2.5 survivor curve is an excellent fit of the original curve based on the company's retirement experience for the period 1951-2007. The proposed 60-R2.5 survivor curve is within the range of estimates used by other gas companies and is consistent with the outlook of company management. The original and smooth survivor curves are plotted in Appendix A on page A-46 of Exhibit C (Future). The original life table for the 1951-2007 experience band is set forth on pages A-47 through A-50.

The calculation of annual depreciation, the second phase, for the original cost of Mains in service at September 30, 2011, is presented by vintage in Appendix B on pages B-44 through B-46 of Exhibit C (Future) for Gas Plant in

Service. The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1991 and prior vintages.

The accrued depreciation for vintages subsequent to 1991 was calculated by the equal life group procedure using the Iowa 60-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 60-R2.5 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 60-R2.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page B-46 of Exhibit C (Future) was brought forward to column 7 of Table 1 on page III-5 of the exhibit and divided by the total original cost in column 3 in order to calculate the annual depreciation accrual rate in column 6.

Q. Is the procedure you described for Account 376 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as the straight line method and the average service life and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 25 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2011, is presented by vintage in Appendix B on page B-85 of Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page B-85 of Exhibit C (Future) was brought forward to column 7 of Table 1 on page III-5 of Exhibit C (Future). The calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service at September 30, 2010, is presented by vintage on page A-85 of Exhibit C (Historic) and summarized in Table 1 on page II-4.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span procedure was applied to major structures in Account 375 and 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Appendix B of Exhibit C (Future).

IX. <u>THE NET SALVAGE AMORTIZATION CLAIM</u>

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in

Penn Sheraton Hotel v. Pa. P.U.C., 198 Pa. Super. 618, 184 A.2d 324 (1962) ("*Penn Sheraton*"), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in PPL Gas Utilities Corporation's (PPL Gas) most recent rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the company's Annual Depreciation Reports submitted each year to the Commission.

As shown in Exhibits C (Historic) and C (Future), UGI-CPG is continuing to amortize all amounts in the depreciation reserve for Account 330 as of December 31, 2006, excluding the portion of the reserve equal to the original cost of plant in service, so that such amounts will be eliminated by the end of 2011. Therefore, UGI-CPG is in the process of complying with the Commission's order entered on February 9, 2007 at Docket No. R-00061398.

Q. Earlier in your testimony you indicated that UGI-CPG's annual depreciation expense consists, in part, of $1,077,190 of net salvage amortization. How did you determine that amount?

A. The $1,077,190 is the result of determining the five-year average of net salvage experienced and estimated during the period from October 1, 2006 through September 30, 2011. During this period, UGI acquired PPL Gas Utilities Corporation. The acquisition was finalized on October 1, 2008. PPL

Gas Utilities Corporation's fiscal year ended December 31 while UGI's fiscal year ended September 30. As a result of the acquisition, PPL Gas Utilities Corporation's name was changed to UGI Central Penn Gas, Inc., and the fiscal year was changed to end on September 30. Consequentially, the 2008 fiscal year covered a period of nine months. Therefore, the 60 month period from October 1, 2006 through September 30, 2011 spans five full fiscal years (2007-2011) and one-quarter of a sixth fiscal year (2006). Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI-CPG, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Appendix C of Exhibit C (Future).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items I-A-5, I-A-6, and I-A-7. In general, these responses are self explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the historic and future test years. The response to I-A-6 presents the survivor curves used in the most recent prior general rate proceeding and the annual accrual rates that resulted from the use of these curves. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in Exhibit C (Historic) and Exhibit C (Future) in the section titled “Cumulative Depreciated Original Cost”.

Q. Does this conclude your direct testimony?

A. Yes, it does.