BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for rate increase by City Gas Company of Florida.	DOCKET NO. 030569-GU ORDER NO. PSC-04-0128-PAA-GU ISSUED: February 9, 2004

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

NOTICE OF PROPOSED AGENCY ACTION ORDER GRANTING REQUEST FOR RATE INCREASE AND MODIFYING RATE STRUCTURE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

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I. BACKGROUND

This proceeding commenced on August 15, 2003, with the filing of a petition for a permanent rate increase by City Gas Company of Florida, a division of NUI Corporation (City Gas or the Company). City Gas requested an increase of $10,489,305 in additional annual revenues. The Company based its request on a 13-month average rate base of $123,421,819 for a projected test year ending September 30, 2004. The Company requested an overall rate of return of 8.10% based on an 11.25% return on equity.

The Company also requested an interim increase of $3,548,987, based on a 13-month average rate base of $120,131,684, at a 7.21% rate of return using a 10.50% return on equity. The interim test year was the period ended September 30, 2002.

However, we only granted an interim increase of $2,942,306 by Order No. PSC-03-1217-PCO-GU, issued October 27, 2003. In that Order, we found the Company's jurisdictional rate base to be $120,124,181 for the interim test year, and its allowed rate of return to be 7.30%, using a return on equity of 10.50%.

This Commission last granted City Gas a permanent increase of $5,132,356 by Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, in Docket No. 000768-GU, In Re: Petition for a rate increase by City Gas Company of Florida. In that Order, we found the Company's jurisdictional rate base to be $120,930,316 for the projected test year ending September 30, 2001. The allowed rate of return was found to be 7.88% for the test year using an 11.50% return on equity.

Pursuant to Section 366.06(4), Florida Statutes, City Gas requested to proceed under the rules governing Proposed Agency

Action (PAA). We have jurisdiction pursuant to Sections 366.04, 366.05 and 366.06, Florida Statutes.

Customer meetings were held in Coral Gables on October 29, 2003, and in Port St. Lucie and Melbourne on October 30, 2003. The purpose of these meetings was to allow the public to offer comments concerning City Gas's requested permanent rate increase and the quality of service provided. Eight customers spoke at the customer meeting in Coral Gables, four spoke at Port St. Lucie, and eight spoke in Melbourne. Also, many customers submitted written comments concerning the requested rate increase and quality of service provided by City Gas.

Four views were common among customers: the proposed revenue increase was too high; the proposed rate structure unfairly targeted residential customers; too many bills were estimated; and some City Gas customer service staff were unable to answer questions about the rate increase.

Customers did not go into detail about why they viewed the proposed revenue increase as too high, although several mentioned that it seemed conflicting that the Company pointed to lack of customer growth as a reason for less than anticipated revenues, yet cited customer growth as a reason why its expenses had increased. We have reviewed the impact of customer growth on expenses and billing determinants in the appropriate sections of this Order. Also, we have reviewed the proposed rate structure and various proposed charges and discuss our findings in the <u>Cost of Service and Rate Design</u> section of this Order.

As regards to quality of service, we have reviewed the frequency of estimated bills, City Gas's inability to answer some questions, the customer comments at the Customer Meetings, and the level of complaints over the past two years and discuss them in the <u>Quality of Service</u> section of this Order.

To allow our staff time to continue its investigation of expenses related to charges allocated to City Gas from NUI Corporation (NUI), City Gas waived for five days the 5-month statutory requirement for a Commission vote on proposed agency action. Based on this waiver, we deferred action on the recommendation filed for the January 6, 2004, Agenda Conference.

Also, the Company supplied our staff with new information relating to its customer retention marketing programs. The appropriate allocation of expenses from NUI and the additional information supplied by the Company are addressed in the appropriate sections of this Order.

II. TEST PERIOD

A. Projected Test Period

The Company used actual data for the 2002 test year rate base, net operating income and capital structure. The 2004 projected test year balances were prepared using a combination of 2002 data trended for expected inflation, customer growth, and payroll growth, specific budgeted increases, or actual balances at May 2003 trended for expected growth. Our auditors and staff have also analyzed certain plant additions in fiscal year 2003.

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. New rates for City Gas will go into effect about 30 days after the January 20, 2004 agenda, or about February 19, 2004. City Gas's 2004 fiscal year begins October 1, 2003, and ends September 30, 2004. Therefore, fiscal year 2004 is an appropriate test year.

Set out below are adjustments we have made to City Gas's projected test year. With the inclusion of these adjustments, the actual data for 2002 and the projections of City Gas's financial operations for 2004 are sufficient to use as a basis for setting rates.

B. Forecasts of Customers and Therms

Our staff reviewed the projected billing determinants contained in minimum filing requirement (MFR) Schedule G-2, pages 6 through 11, for fiscal years 2003 and 2004 by analyzing the appropriateness of the Company's forecasting methodology, the consistency of the projected values with historical trends, and comparing the projections to the latest available actual data. Based of these analyses, we find that the billing determinants contained in MFR Schedule G-2 shall be approved with the exception of the GS-100 rate class which shall be adjusted to reflect our disallowance of the Company's Customer Retention Program.

As described in the direct testimony of Company Witness Nikolich, the billing determinants for the Residential and Commercial rate classes were projected using multiple regression techniques, while customers in the Industrial classes were projected individually based on customer survey data and historical trends. For the Residential and Commercial rate classes, customer growth by rate class was projected based on estimates from the Company's Marketing and Engineering Departments. These departments maintain contact with local governmental authorities and developers. The information obtained from these contacts form the basis of the customer growth estimates for each of the three operating divisions of the Company. The number of therms was projected on a per customer basis using multiple regression techniques. Variations in therm usage per customer were modeled using economic, climatological, and time-trend variables. Having evaluated the assumptions, statistical properties, and output of these models, we find them to be appropriate. Finally, the Company's estimates of total therms by rate class was calculated by multiplying the projected number of customers by the projected therm use per customer.

In response to a request for production of documents, the Company provided historical monthly customer and therm data by rate class for the period October 1996 through September 2002. Additionally, the Company provided the fiscal year 2003 forecast variance report which contained actual customer and therm data by rate class for the October 2002 through September 2003 time period. Taken together, this data provided seven years of historical data immediately preceding the 2004 test year. This data was used to provide a historical context for evaluating the projected test year data presented in MFR Schedule G-2.

Our staff analyzed tabular and graphical representations of this data to determine if the projected data for the 2004 test year appeared consistent with historical trends. For the Residential and Commercial rate classes, the projected test year billing determinants closely match the long-term and seasonal variations displayed by the historical data. Therefore, we find that the billing determinants for these rate classes are consistent with historical growth patterns.

The billing determinants for the Industrial rate classes, however, show a marked increase in the test year compared to the actual 2003 year-end Industrial customer counts. In response to an inquiry by our staff, the Company explained that the increase in test year Industrial customers reflected new accounts that had been delayed during the recent economic downturn, but that are anticipated to come on-line during the test year.

Finally, our staff produced an alternate test year forecast by applying the projected test year month-to-month changes in customers contained in MFR Schedule G-2 to the latest (September 2003) historical data. This had the effect of updating the Company's customer forecast by approximately six months. Test year therms were then calculated by multiplying the updated customer projections by the Company's 2004 therms per customer estimates. Test year revenues were calculated by multiplying the updated customer projections by the Company's 2004 revenue per customer estimates derived from the data contained in MFR Schedule G-2. A comparison of this alternate forecast to the Company's forecast is shown in the following table:

Projected Number of Customers, Therms, and Revenues for 2004				
	Residential	Commercial	Industrial	Total
Customers				
Company	96,209	5,505	93	101,807
Staff	95,831	5,481	83	101,395
% diff.	-0.4%	-0.4%	-10.5%	-0.4%
Therms				
Company	19,787,230	46,124,374	45,370,957	111,282,561
Staff	19,732,711	45,930,454	40,697,326	106,360,490
% diff.	-0.3%	-0.4%	-10.3%	-4.4%
Revenues				
Company	$37,624,556	$29,130,638	$7,425,657	$74,180,851
Staff	$37,476,536	$29,004,085	$6,642,953	$73,123,573
% diff.	-0.4%	-0.4%	-10.5%	-1.4%

As shown in the table, the effect of updating the Company's forecast to reflect the latest available actual data has a very small negative impact on the Residential and Commercial rate class projections. For the Industrial rate classes, however, our staff's updated projections fall approximately 10% below the Company's forecasts. This difference reflects the Company's assertion discussed above that several delayed Industrial customer projects will come on-line during the test year. Since accepting the Company's assertion will not have an adverse impact on the rates for existing Industrial customers, we find it is appropriate to accept the Company's assertion that its projected Industrial customer growth will occur some time during the test year.

As discussed below, we are denying the Company's request for cost recovery of the Customer Retention Program targeting residential customers in the Miami area. Without this program, the Company indicates that, in addition to the forecast attrition, it would lose an additional 348 customers at an annual therm usage of 180 therms per customer. Because we are denying the Company's request for recovery of the expenses of this program, we find that it is appropriate to reduce the number of customers and therms by the amounts the program would have retained. Therefore, the Company's number of projected test year therms shall be reduced by 62,640 (348 customers x 180 therms/customer).

Based on this adjustment, the Company's projected test year customers and therms presented in MFR Schedule G-2, adjusted for the removal of the Customer Retention Program, are appropriate for setting rates.

III. QUALITY OF SERVICE

As stated above, our staff conducted three customer meetings at which a total of twenty customers spoke. Several customers complained at the customer meeting that they were not happy having their meters estimated so often.

On December 8, 1997, this Commission granted City Gas authority to implement a bi-monthly meter reading program by Order No. PSC-97-1534-FOF-GU, issued December 8, 1997, in Docket No. 971074-GU, In re: Petition for authority to implement bi-monthly meter reading program by City Gas Company of Florida. The program was implemented in part to reduce costs; however, missing one actual meter reading results in three consecutive estimated bills.

One customer who spoke complained that his meter was estimated three consecutive months during which time his gas heater broke and he had no gas consumption. Based on prior usage, City Gas billed him and he paid hundreds of dollars above what his charge would have been had his meter been read instead of estimated. Based on this reduced usage, at about $30 per month, it would take many months for this customer to use up his credit. The Company indicated that it would investigate this complaint and advise our staff of any subsequent actions taken. A few weeks later the Company advised our staff that the problem had been resolved. Our staff called the customer to verify that everything was okay and the customer stated that his complaint was totally resolved and he was "very satisfied."

City Gas maintains a webpage on its website devoted to instructing its customers how estimated bills reduce meter reading costs, how estimated bills are trued up, and what customers can do to help reduce the likelihood that bills are estimated several times in a row. If a scheduled bi-monthly reading does not take place, customers are provided the opportunity to read the meters themselves and report it by way of a toll-free telephone number or the Internet. City Gas employees are required to read each meter at least twice per year.

Additionally, Deloitte & Touche, LLP, provided City Gas with internal audit services in early 2003 regarding gas consumption data flow from metering to invoicing. The independent auditors reviewed recordkeeping procedures, service/meter reader dispatching procedures, and other internal processes that impact the timeliness and accuracy of billing and servicing. In response to audit findings, the Company has taken steps to reduce the likelihood that meters will go unread for extended periods.

Several customers mentioned that some City Gas customer service staff were unable to answer questions about the rate increase or were rude. These appear to be isolated incidents outside of City Gas's policies on customer service.

Our staff reviewed consumer complaints logged by the Division of Consumer Affairs over the past two years. Although City Gas's complaints continue to be the highest of all the regulated gas companies, City Gas's service territory and its higher proportion of residential customers contribute to an expected higher level of complaints. From January 2002 to September 2003, City Gas's complaint level has averaged 0.1165 complaints per 1,000 customers. No complaint has risen to the level that our staff suggests any additional action be taken. There are no safety concerns at this time as well. On the whole, complaints against City Gas's quality of service appear to be minimal. Therefore, we find that City Gas's quality of service is satisfactory.

IV. RATE BASE

A. Inactive Service Lines

City Gas identified 955 inactive service lines in accordance with Rule 25-12.045, Florida Administrative Code. The rule outlines the necessary action for inactive gas service lines that have been used, but have become inactive without reuse. Section (1)(c) of the rule states: "After five years of inactivity, service lines shall be retired and physically abandoned within six months." To physically abandon a service line, the operator must disconnect the service line from all sources of gas at the nearest point to the main. Where the appropriate governmental authority prohibits cutting pavement, the service line shall be disconnected at the nearest point not under a paved surface. Also, the stub of the service line, the short section of the remaining service line to the main, shall be disconnected closer to the main or at the main, if at some later date it becomes accessible during normal operations.

Our staff's audit review showed that of the four divisions reviewed, Miami/Hialeah and Treasure Coast divisions had 950 and 5 inactive service lines, respectively. In response to our staff's Second Set of Interrogatories, City Gas listed the 955 inactive service lines ranging from 1983 through 1998. The majority of the inactivity occurred during 1991, 1992, and 1995. Based upon the information provided, the 955 inactive service lines shall be removed from the projected test year for ratemaking purposes, and the associated cost removed from plant in service, accumulated depreciation, and depreciation expense for the projected test year.

B. Total Gas Plant in Service

Based upon our adjustment above, the appropriate amount of Gas Plant in Service for the projected test year is $198,324,265.

C. Common Plant Allocated from NUI

In its MFRs, on Schedule G-1, Page 1 of 28, for the projected test year, the Company included an allocated portion of NUI Headquarters' Corporate Assets, related Accumulated Depreciation and Depreciation Expense. These amounts were based on actual expenditures and budgeted amounts for capital investments at the NUI corporate level that support utility operations in Florida and other states. A portion of this investment is allocated to City Gas by adjustment.

The Company filed its MFRs on August 15, 2003. On September 26, 2003, NUI announced that its Board of Directors had established a Special Committee of independent directors to pursue the sale of NUI. Following this announcement, our staff asked the Company to provide a list of projected capital spending reductions resulting from its intention to sell NUI. Pursuant to Audit Exception No. 2, and further inquiries, the Company provided a comprehensive list of $11,543,833 projected capital spending reductions. Of the $11,543,833 in reductions, $6,000,000 relates to the projected Billing System and the other $5,543,833 applies to numerous plans, including $2,300,000 for Phase Two of the Disaster Recovery Project and $475,000 of software and hardware costs for its projected treasury automation and integration.

In summary, as a result of its projected corporate capital spending reductions due to the intent to sell NUI, Common Plant Allocated shall be reduced by $1,766,884, Accumulated Depreciation - Common Plant Allocated shall be reduced by $119,520, and Common Plant Depreciation and Amortization shall be reduced by $302,961.

In our staff's review of additions to NUI common plant, a number of costs were found which were leasehold improvements for tenants or affiliated companies. These costs should have been directly billed to the tenants or charged to accounts of the affiliated companies. Due to NUI recording these costs on their books, the costs were allocated down to City Gas.

The specific costs were itemized in Audit Exception No. 3 and reviewed by City Gas. City Gas explained in more detail the nature of two of the costs, indicating that the costs supported the activities of NUI and were properly allocated to City Gas. The Company agreed that the remainder of the costs should be removed.

The adjustments to remove costs related to tenants or affiliated companies are reductions to Common Plant Allocated in the amount of $570,346, Accumulated Depreciation - Common Plant Allocated in the amount of $65,149, and Depreciation and Amortization - Common Plant Allocated in the amount of $15,930.

D. Common Plant - Non-Utility Operations

Pursuant to our staff Engineering Report, approximately 7,600 square feet of regulated utility usage has been eliminated from the Titusville Gate property since the previous rate case. This decrease in utility usage increases the allocation to non-utility from 72% to 83.7%. To account for this, an adjustment shall be made to reduce Account 374 - Land, by $2,697 for the projected test year.

A review of the allocation of the Rockledge Office and Port St. Lucie property shows that 18.9% is used for non-utility purposes. The Company used a non-utility rate of 12% for structures and improvements to that property. The structures and improvements to the property shall be allocated using the same percentage. To do this, Account 375 - Structures & Improvements shall be reduced by $394 ($134 and $260 for the Rockledge and Port St. Lucie properties, respectively). Similarly, Accumulated Depreciation and Depreciation Expense associated with Account 375 - Structures & Improvements shall be reduced by $260 ($122 + $38) and $10 ($3 + $7), respectively.

The Rockledge and Port St. Lucie allocations also affect Account 390 - Structures & Improvements, and its related Accumulated Depreciation and Depreciation Expense. These shall be reduced as well to reflect the higher non-utility rate. To do this, Account 390 - Structures & Improvements shall be reduced by $31,657 ($30,310 for Rockledge and $1,347 for Port St. Lucie); Accumulated Depreciation shall be reduced by $14,116 ($13,876 + $240); and Depreciation Expense shall be reduced by $751 ($715 + $36). Based on these adjustments, Common Plant shall be reduced by a total of $34,748; accumulated depreciation shall be reduced by $14,376; and Depreciation Expense shall be reduced by $761.

E. Total Common Plant Allocated

Based on the above adjustments, the appropriate amount of Common Plant Allocated for the projected test year is $3,351,037.

F. Acquisition Adjustment

On MFR Schedule G-1, Page 1 of 28, City Gas has shown an Average Unadjusted Acquisition Adjustment of $30,832,927. To this amount, it made an adjustment of $29,370,230 to remove the acquisition adjustments related to the acquisition of City Gas by NUI and the Fort Pierce Utilities acquisition, resulting in an Average Adjusted Acquisition Adjustment of $1,462,697. These two adjustments were disallowed by this Commission in earlier proceedings.

Also on MFR Schedule G-1, Page 1 of 28, City Gas has shown Average Unadjusted Accumulated Amortization - Acquisition Adjustment of $15,387,056. Of this amount, $15,160,584 is adjusted out for the amortization of the two disallowed acquisition adjustments mentioned above, resulting in Average Adjusted Accumulated Amortization - Acquisition Adjustment of $226,472.

The related amortization expense of $46,740 is shown on MFR Schedule G-2, Page 1 of 34, as part of the Per Books Depreciation and Amortization Expense of $7,395,579. The $46,740 excludes the amortization related to the two disallowed acquisition adjustments. Therefore, we find that the Company's projected amounts for the Acquisition Adjustment - $1,462,697, the Accumulated Amortization of Acquisition Adjustment - $226,472, and the related Amortization Expense - $46,740, are appropriate for the projected test year, and no further adjustments are warranted.

G. Construction Work in Progress (CWIP)

Upon review of the projected amounts in the CWIP account, we find that City Gas's CWIP of $6,452,439 for the projected test year is appropriate.

H. Total Plant

Based on the above, we find the appropriate amount of Total Plant for the projected test year to be $209,590,438.

I. Accumulated Depreciation of Gas Plant in Service

Based upon our adjustments for Inactive Service Lines, Non-utility Depreciation Expense, and the change in depreciation rate, the Company's Accumulated Depreciation of $84,927,235 shall be reduced by $150,790 for an appropriate Accumulated Depreciation of Gas Plant in Service for the projected test year of $84,776,445.

J. Accumulated Depr. and Amortization of Plant in Service

Based on our adjustments above, the appropriate amount of Accumulated Depreciation and Amortization of Plant in Service for the projected test year is $87,471,410, and not the $87,821,245 amount projected by the utility.

K. Interest Accrued in Working Capital

The Company included Average Unadjusted Interest Accrued of $1,336,328 in its Working Capital Allowance (WCA) on MFR Schedule G-1, Page 3. To calculate the appropriate amount of Interest Accrued to include in WCA, City Gas used the ratio of City Gas debt to NUI Utilities debt and applied that ratio to NUI Utilities' interest payable. This pro rata interest payable was then compared to City Gas's Unadjusted Interest Accrued and an adjustment was made, for the difference, decreasing Interest Accrued by $198,324. However, misstated amounts were used for NUI Utilities debt in this calculation, and the pro rata ratio of City Gas debt to NUI Utilities debt was not accurate. Using the correct debt amounts and ratio, the adjustment should have been to decrease Interest Accrued by only $97,685.

Since Interest Accrued was decreased by $198,324 when it should have been decreased by only $97,685, an adjustment increasing Interest Accrued, and thereby decreasing working capital by $100,639, is needed.

L. Accrued Taxes and Tax Collections Payable

Per MFR Schedule G-1, Page 3 of 28, the Company proposed a credit amount of $146,963 for Taxes Accrued - General, and a debit amount of $486,363 for Tax Collections Payable for the projected test year.

The Company included $132,944 of Taxes Accrued related to Regulatory Assessment Fees (RAFs). Later in this Order, we are making an adjustment to RAFs. Using the recalculated RAFs, the resulting 13-month average liability is $59,739. Therefore Taxes Accrued - General shall be decreased by $73,205 to reflect the correct balance of the liability related to the RAFs.

The Company also included $388,405 for Accrued Property Taxes in the Taxes Accrued - General. Because we are recalculating Property Taxes later in this Order, we find that the correct 13-month average is $704,510. Therefore Taxes Accrued - General shall be increased by $316,105 to reflect the correct balance of the accrued property taxes payable account.

In its Tax Collections Payable, the Company included a debit balance of $477,129 for Payroll Deduction - Employee - FICA (Acct. 218000), and a debit balance of $593,283 for Payroll Deduction - Employee - FIT (Acct. 218001). In response to a staff inquiry, the Company stated:

> Both of these accounts have large debit balances because they record the disbursements made each pay cycle for the employee's portion of these taxes. The offsetting credit was being recorded on another business unit's books. This has since been corrected and the disbursements are now made from the same account in which the collections are recorded.

The balances in these accounts are expected to be zero going forward; therefore, Tax Collections Payable shall be increased by $1,070,412 ($477,129 + $593,283).

In addition, the Company inadvertently included in Tax Collections Payable a net credit balance of $3,224 associated with payroll-related income taxes for New Jersey, Pennsylvania, North Carolina, and Maryland. An adjustment to decrease Tax Collections Payable by $3,224 is appropriate inasmuch as these liabilities do not relate to City Gas's operations.

In summary, based on the above adjustments, Taxes Accrued - General shall be increased by $242,900, and Tax Collections Payable shall be increased by $1,067,188, resulting in a net decrease to WCA of $1,310,088.

M. Under and Over-Recoveries in Working Capital

In its WCA, MFR Schedule G-1, Page 2, the Company included a net over recovery of Purchased Gas Revenue of $1,425,345 and a net over recovery of Energy Conservation Revenue of $907,340, for a total over recovery of $2,332,685.

On Page 11 of Witness Lopez's prefiled testimony, she states,

> Both ECCR and fuel costs are projected to be over-recovered in 2004. Consistent with Commission guidelines, City Gas left these over-recoveries in working capital, as a reduction of rate base.

Commission practice has been to exclude under recoveries, which are assets, from working capital and to include over recoveries, which are liabilities, in working capital. The rationale for excluding under recoveries is that the ratepayer is paid the commercial paper rate by the Company through the clause mechanism, but at the same time, if included in working capital, the Company would be allowed to earn the overall rate of return on the increased rate base. This asymmetrical treatment would give the Company a bonus instead of a penalty when cost under recoveries occur because the overall cost of capital is higher than the commercial paper rate.

The rationale for including over recoveries as a reduction to working capital is to provide the Company with an incentive to make its projections for the cost recovery clause as accurate as possible and avoid large over recoveries.

Based on the above discussion and the Company's position as reflected in its MFRs, the Company has appropriately reflected under recoveries and over recoveries in the WCA.

N. Asset Retirement Obligations

The Financial Accounting Standards Board issued Statement No. 143, Accounting for Asset Retirement Obligations (SFAS 143) in June 2001. This statement applies to legal obligations associated with the retirement of long-lived assets. Rule 25-14.014, Florida Administrative Code, states that SFAS 143 "shall be implemented by each utility in a manner such that the assets, liabilities and expenses created by SFAS 143 and the application of SFAS 143 shall be revenue neutral in the rate making process."

SFAS 143 was effective for financial statements issued for fiscal years beginning after June 15, 2002. Therefore, for City Gas, the implementation date was the fiscal year beginning October 1, 2002 and ending September 30, 2003.

Following an internal review, the Company determined that its galvanized replacement program in Florida fell within the intention of SFAS 143, based on City Gas's commitment to this Commission that it would replace the pipe in the galvanized replacement program.

In response to inquiries by our staff, the Company provided journal entries for the initial recognition of the Asset Retirement Obligation (ARO) which it recorded in fiscal year ended September 30, 2003, and its period-to-period monthly accounting for the same period. Based on review of this information and the ARO entries in the MFRs, SFAS 143 has been recorded and projected so that it is revenue neutral, and, therefore, is in substantial compliance with Rule 25-14.014, Florida Administrative Code.

However, during conversations with the Company, it was learned that the journal entries to record the initial recognition and the period-to-period entries for 2003 have not been reviewed by the

Company's external auditors. The entire ARO issue will be reviewed in conjunction with PricewaterhouseCoopers, LLP's review for the September 30, 2003 Annual Report to the stockholders. In conversations with a Company representative, our staff learned that the Company's initial correspondence with PricewaterhouseCoopers, LLP, indicates that the Company is still unsure if the ARO recognition is required. For this reason, ARO entries that have been recorded may be reversed prior to issuance of the annual report.

For this proceeding, the recording of the ARO as it relates to its galvanized replacement program is in accordance with Rule 25-14.014, Florida Administrative Code, Accounting for Asset Retirement Obligations under SFAS 143, as it is revenue neutral.

O. Deferred Piping

The Company included $12,593,913 for Deferred Piping as part of its deferred debits in its WCA. In response to a staff inquiry, the Company provided a revised Deferred Piping schedule. This revised schedule showed that Deferred Piping for the projected test year should be $12,656,219, a $62,306 increase to Deferred Piping and WCA.

The Company also included Deferred Piping - Accumulated Amortization of ($12,187,476) in its WCA. We have recalculated the 13-month average Deferred Piping - Accumulated Amortization to be ($12,188,575), resulting in an increase to Accumulated Amortization of Deferred Piping and a decrease to WCA of $1,099.

The analysis of Deferred Piping, Accumulated Amortization of Deferred Piping, and Amortization of Deferred Piping is discussed later in this Order.

P. Total Working Capital

Based on our adjustments above and our subsequent adjustment for odorant costs, we find the appropriate amount of Working Capital for the projected test year is ($2,221,581), and not the ($864,289) amount reflected by the Company.

Q. Total Rate Base

Based on the adjustments above, we calculate City Gas's Rate Base to be $119,897,447 for the projected test year and not the $123,421,807 amount projected by the utility. Our calculation of rate base is shown on Attachment 1.

V. COST OF CAPITAL

A. Accumulated Deferred Income Taxes

The Company has included accumulated deferred taxes of $7,131,147 in its 2004 projected test year capital structure. The per book amount of $12,469,007 is reduced by $5,337,860 for the deferred taxes related to the NUI acquisition adjustment. This adjustment is consistent with its prior rate cases.

In September 2003, the Company recorded an increase in deferred taxes of $1,535,859 related to the fiscal year ended September 30, 2002. This amount was not included in the MFRs. Therefore, we have increased deferred taxes by this amount.

Deferred taxes are usually increased when tax depreciation is greater than book depreciation. For the fiscal years ended 2003 and 2004, tax depreciation was greater than book depreciation. This difference should result in an increase to deferred taxes. However, the deferred taxes in the balance sheet reflected a decrease. We have increased the amount of deferred taxes by $3,093,906 to reverse the decrease and reflect the increase in this account each year.

The Company made an adjustment of $8,128,136 to plant in service to include the amount of common plant allocable from NUI to City Gas. The accumulated depreciation related to this plant is $3,821,245. Earlier in this Order, we decreased the amount of common plant and accumulated depreciation allocated to City Gas by a net amount of $2,152,561.

Additionally, the Company has removed common plant of $2,405,121 that is allocated to the leased appliance business. The accumulated depreciation related to this plant is $1,153,707. In the Common Plant - Non-Utility Operations section of this Order, we adjusted the amount of common plant and accumulated depreciation allocated to NUI by a net amount of $20,372.

Based on the Company's net allocations of common plant and our adjustments noted above, the net amount of common plant allocated to the Company, less accumulated depreciation, is $882,544.

However, the Company did not include an adjustment for the deferred taxes related to this common plant allocation in its MFRs. We have determined the amount of deferred taxes related to this common plant allocation to be $84,063. As a result, we have increased deferred taxes by this amount.

The net result of the above-mentioned adjustments indicates that the 13-month average balance of deferred taxes shall be increased by $4,713,871. With this increase, the appropriate amount of accumulated deferred taxes to include in the capital structure is $11,845,018.

B. Unamortized Investment Tax Credits (ITCs)

The Company proposes to include ITCs of $536,361 in its projected 2004 test year capital structure at zero cost. The ITCs included in the capital structure are specifically related to plant included in rate base. This treatment is consistent with the treatment in its last rate case, and is therefore appropriate.

C. Rate Base and Capital Structure Reconciliation

In reconciling rate base and capital structure, City Gas made adjustments to its capital structure to reflect the investor capital ratios of NUI Utilities, Inc. (NUI Utilities). City Gas is a division of NUI Utilities. City Gas relies on NUI Utilities as the source of capital and does not issue its own debt or equity. Therefore, the capital structure for NUI Utilities is reasonable to use for City Gas in determining the appropriate cost of capital. NUI Utilities is a subsidiary of NUI Corporation.

City Gas forecasted NUI Utilities' balance sheet for the test year ending September 2004. City Gas removed lease appliances supported by this balance sheet by specifically identifying accounts associated with the leased appliances. City Gas removed an amount for non-utility common plant directly from NUI Utilities' equity balance. The result was an equity ratio of 48.53%, a long-term debt ratio of 50.39%, and a short-term debt ratio of 1.09%. City Gas adjusted its ratios for investor capital to conform with these ratios based on NUI Utilities. This capital structure derivation is generally consistent with the derivation this Commission used in City Gas's last rate case.

To forecast the balance sheet for NUI Utilities for the projected test year, City Gas began with NUI Utilities balance sheet as of May 31, 2003. City Gas trended these balance sheet amounts forward to derive a capital structure for the projected test year. City Gas reduced the amount of short-term debt on that balance sheet by the amount of receivables due to NUI Utilities from NUI Corporation. This significantly reduced the amount of short-term debt in City Gas's capital structure. However, according to the balance sheet for NUI Utilities as of September 30, 2003, the amount of short-term debt was $132,400,000.

The capital structure for NUI Utilities has been affected by financial problems that NUI Corporation has experienced. NUI Corporation faces significant financial problems related to unprofitable non-utility businesses. These problems have led to downgrades in the bond ratings of both NUI Corporation and NUI Utilities. The current Standard and Poor's bond rating for NUI Utilities is BB, which is below investment grade. In addition, the New Jersey Board of Public Utilities and the New Jersey Attorney General's office are investigating certain questionable transactions associated with NUI Energy Brokers, which is a subsidiary of NUI Corporation. The problems have also prompted NUI Corporation to seek a buyer for the entire Company.

As of November 24, 2003, NUI Utilities refinanced its short-term debt with payments of all receivables from NUI Corporation and with a $50 million term loan from a group of banks. The cost rate for the $50 million term loan is 7%, and we will address whether this is the appropriate cost rate in the next section of this Order.

We find that the $50 million in short-term debt shall be included in the forecasted capital structure, and we have included an updated trended equity amount based on the more current

September 30, 2003 balance sheet. These adjustments update the forecasted balance sheet for NUI Utilities.

We did not make any specific adjustments to NUI Utilities capital structure to remove amounts for non-utility investment. Historically, in reconciling rate base and capital structure, this Commission has removed amounts for non-utility investments solely from common equity. This method discourages utilities from subsidizing higher risk non-utility investments with the generally low risk capital structure and cost of capital of the utility. We note that City Gas's non-utility adjustment related to non-utility common plant, which is an allocation and is indistinguishable as a risk category from utility investment. NUI Utilities does have leased appliances in Florida and New Jersey as non-utility investments. Leased appliances are closely related to the regulated gas distribution business and may encourage customer retention. In previous cases with City Gas, an amount for leased appliances has not been removed specifically from common equity because the adjustment would have caused City Gas's equity ratio to be too low.

After the above adjustments, the resulting capital structure has the following investor capital ratios: 43.35% common equity, 47.55% long-term debt and 9.10% short-term debt. This is a reasonable capital structure given that City Gas's equity ratio in its previous rate case was 43.38%. Additionally, our water and wastewater leverage formula is based upon an index of gas distribution companies and the average equity ratio for this group is 44.48%. (See Order No. PSC-03-0707-PAA-WS, issued July 13, 2003, in Docket No. 030006-WS, <u>In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.</u>, which was consummated by Order No. PSC-03-0799-CO-WS, issued July 8, 2003.)

<u>D. Cost Rate for Short-Term Debt</u>

In its filing, City Gas proposed a short-term debt cost rate of 2.91% based on an amount of $5,646,606 for NUI Utilities. On November 24, 2003, NUI Utilities refinanced its short-term debt by receiving payments of receivables from NUI Corporation, its parent company, and with a $50 million term loan. The interest rate formula for the term loan is essentially the Euro Rate plus 5.0%. Currently, the interest rate for the term loan is 7.00%.

In the previous section of this Order, we noted that NUI Corporation has experienced financial losses and problems associated with its non-utility operations. These problems have had a negative impact on the creditworthiness of NUI Utilities.

We believe that if NUI Utilities stood alone its credit rating would be higher than its current rating. This would allow NUI Utilities to obtain the term loan with an interest rate lower than 7.00%. City Gas provided an analysis showing that a reasonable, arms-length interest rate for the term loan for City Gas would be 3.9%. We also note that the current prime rate is 4.0%, and find that the 3.9% is acceptable. This cost rate for short-term debt should help insulate City Gas's customers from the financial problems of NUI Corporation.

E. Cost Rate for Common Equity

In its filing, City Gas uses 11.25% as the cost rate for common equity. The 11.25% is based on the testimony of Dr. Roger Morin, City Gas's cost of equity expert.

In his testimony, Dr. Morin emphasizes that he is treating City Gas's natural gas business as a separate stand-alone entity, distinct from both NUI Corporation and NUI Utilities. He notes that the cost of equity in this case should reflect the risk of City Gas's natural gas distribution operations in Florida and that NUI Corporation is the equity investor.

To estimate the cost of equity for City Gas, Dr. Morin employed three methodologies: the Capital Asset Pricing Model (CAPM), the risk premium model, and the Discounted Cash Flow model (DCF). He notes that using several approaches allows one to serve as a check on the others.

Pursuant to the CAPM, he estimated a 10.6% cost of equity. However, he notes that financial literature supports the notion that betas below 1.0 underestimate the cost of equity. Adjusting for this using an expanded CAPM (ECAPM) analysis results in a revised 11.1% cost of equity estimate.

Risk premium approaches for estimating the cost of equity are based on adding a risk premium to a current cost rate for debt. The risk premium reflects the higher risk associated with equity investments compared with debt investments.

For his risk premium methodologies, Dr. Morin calculated historical risk premiums based on the actual return on equity for Moody's Natural Gas Distribution Index and either Treasury bond yields and A-rated utility bonds. The results are 11.1% using Treasury bonds and 11.8% using A-rated utility bonds.

Dr. Morin also examined historical risk premiums implied by returns on equity (ROEs) allowed by regulatory commissions for the period 1994 through 2003. The results are 11.1% using Treasury bond yields and 11.3% using A-rated utility bonds.

The DCF method is based on the theory that the value of a security is the present value of future cash flows, such as dividends, associated with the security. The cost of equity is the discount rate used to reflect the present value of the cash flows. The components of a traditional DCF model are the dividend yield and the growth rate in dividends. The dividend yield is the dividend divided by the stock price.

Dr. Morin applied his DCF model to two proxy groups: a group of natural gas distribution companies and a group of investment-grade combination electric and gas utilities. He used growth rates based on earnings growth forecasted by Zacks Investment Research and by Value Line. The results are as follows:

DCF RESULTS	ROE
Natural Gas Distribution Zacks Growth	10.2%
Natural Gas Distribution Value Line Growth	12.1%
Combination Electric & Gas Zacks Growth	9.7%
Combination Electric & Gas Value Line Growth	10.3%

Dr. Morin includes flotation costs in all of his cost of equity estimates. He recommends that investors be compensated for flotation costs on an on-going basis. His recommended allowance is approximately 30 basis points and is based on a 5% adjustment to the dividend yield component of equity costs. The 5% consists of 4% for direct costs and 1% for market pressure.

The results of Dr. Morin's cost of equity studies are presented below:

STUDY	ROE
CAPM	10.6%
ECAPM	11.1%
Risk Premium Natural Gas T-Bonds	11.1%
Risk Premium Natural Gas A-rated Bonds	11.8%
Allowed Risk Premium T-Bonds	11.1%
Allowed Risk Premium A-rated Bonds	11.3%
DCF Natural Gas Zacks Growth	10.2%
DCF Natural Gas Value Line	12.1%
Combination Electric & Gas Zacks Growth	9.7%
Combination Electric & Gas Value Line Growth	10.3%

For these results, Dr. Morin notes that the average, the median, and the truncated mean are all very close to 11%. He believes 25 basis points should be added to the 11% because City Gas is smaller than the natural gas companies in his proxy groups. He notes that, as of the date of his testimony, NUI Utilities has an S & P bond rating of BBB and a Moody's bond rating of Ba1, which is below investment grade. Currently, S & P rates NUI Utilities BB, which is below investment grade. The difference in yields between BBB utility bonds and A-rated utility bonds is approximately 50 basis points. This might imply an adjustment of 50 basis points to allow for City Gas's lower bond rating and higher risk compared with the companies in the proxy groups. However, Dr. Morin believes only 25 basis points is necessary because City Gas operates in a favorable regulatory environment. Therefore, he concludes that 11.25% is the appropriate cost rate for common equity for City Gas.

We do not agree with all the methods and inputs that Dr. Morin used in his various studies. For example, for two of his risk premium studies, Dr. Morin relies upon historical earned returns and bond yields to calculate a risk premium. We believe the risk premium should be prospective and based on investors' required returns, which in turn are based on investors' expectations of risk and return. Also, Dr. Morin uses earnings growth in his DCF models. We find that some consideration of Value Lines' forecasted dividend growth rates is important.

Despite these disagreements with Dr. Morin about methodology and inputs, we find that the 11.25% is reasonable. City Gas is smaller than the companies in Dr. Morin's proxy groups. Unlike City, the natural gas companies in these groups tend to have considerable market power based on high residential heating loads. In contrast, City Gas is losing residential customers.

In the recent rate case for Peoples Gas System, we approved a stipulation that set the cost rate for common equity at 11.25%. City Gas is smaller than Peoples Gas System and, at 43.35%, has a lower equity ratio.

Therefore, we approve an 11.25% cost rate for common equity. For all regulatory purposes, the 11.25% is the mid-point for rate setting and the appropriate range is plus or minus 100 basis points.

F. Weighted Average Cost of Capital

City Gas's proposed weighted average cost of capital is 8.10%. However, we have adjusted the short-term debt cost rate. Using the appropriate cost rate for common equity of 11.25%, and the correct balance for deferred taxes of $12,041,405, we reconciled rate base to the capital structure by making specific adjustments and by prorating adjustments over investor sources of capital. With these adjustments and cost rates, the appropriate weighted average cost of capital for the projected test year is 7.36%. Our calculation of the cost of capital is presented on Attachment 2.

VI. NET OPERATING INCOME

A. Purchased Gas Adjustment Revenues, Expenses, & Taxes-Other

On Schedule G-2, Page 1, the Company included Purchased Gas Revenues of $30,972,215 and Purchased Gas Costs of $31,127,076. The Company then removed Purchased Gas Revenues of $31,127,076 and Purchased Gas Costs of $31,127,076.

Upon further examination and discussions with the Company, it was determined that the Company should have removed Purchased Gas Revenues of $30,972,215 and Purchased Gas Costs of $31,127,076. The correction to the Company's adjustment decreases the Company's Purchased Gas Revenue Adjustment by $154,861 ($31,127,076 - $30,972,215), which increases Adjusted Revenues by the same amount.

B. Projected Total Operating Revenues

Per MFR Schedule G-2, Page 2, the Company shows adjusted revenue of $37,873,588. In reconciling this to MFR Schedule H-1, Page 10, there is a discrepancy in the revenue amounts, and, based on the billing determinants, revenues must be increased by $52,935. Our calculation of the estimated revenues at present rates shows that an increase to revenues of $31,589 is required to correct two errors in the Company's calculation. The remaining $21,346 increase reconciles the remaining immaterial calculation difference between the two sets of MFR schedules.

In reconciling the Total Present Other Operating Revenue per MFR Schedule H-1, Pages 1 and 6, an error in the Company's calculation requires a decrease in revenue of $77,355.

Finally, we have denied the expenses associated with the Company's proposed marketing programs to both retain existing customers and attract new customers. Because we are disallowing the advertising and customer retention program costs, we are also making a downward adjustment in billing determinants and revenue attributable to the 348 customers the company expected to attract or retain as a result of the programs. We have therefore reduced projected total revenues by $62,243, which represents the projected revenues attributable to the 348 customers.

Based on the above we have made three corrections to the Company's operating revenues: an increase of $52,935 based on the projected billing determinants; a decrease of $77,355 due to a Company error; and a decrease of $62,243 to reflect a reduction to projected customers and therm sales, for a net decrease of $86,663 to Projected Total Operating Revenues. We have addressed the decrease to RAFs later in this Order.

C. Clewiston Extension Revenues

The Company's last rate case was Docket No. 000768-GU, with a projected test year ended September 30, 2001. (See Order No. PSC-01-0316-PAA-GU) In that rate case, the Company proposed to construct a natural gas pipeline in three phases from western Palm Beach to Fort Myers Shores, a distance of approximately 150 miles. The project is referred to as the Clewiston Pipeline Extension Project (Pipeline).

As discussed in the above-referenced order, the main reason the Company wanted to construct the Pipeline was the potential to provide service to several large citrus and sugar cane processors in the area. Those processors were not being served by natural gas, and the Company, based on its initial surveys, believed that there was enough interest in taking natural gas service by them, and several other larger commercial accounts, that the Pipeline project would be successful. The Company had no plans at that time to serve residential customers. The Company indicated that the project's annualized customer growth and therm sales associated with the Pipeline extension would increase its test year revenues by approximately $1.9 million. This Commission found that it was appropriate to reflect the first full year of the project's operations in calculating the final revenue requirement.

In the instant case, Company witness Jeff Householder testified that the Company began construction of the Pipeline in July 2001 with the intent of installing Phases I and II. Phase I of the distribution system was placed into service in November 2001. This portion of the Pipeline connects the Florida Gas Transmission West Palm Beach compressor station #21 to South Bay, representing 48 miles of main. At that time, the Company, citing economic downturns and high natural gas prices, decided that it would be imprudent to proceed with the construction of Phase II, and placed the remainder of the project on hold. Mr. Householder testified that: "As the economy rebounds and assuming gas prices stabilize, it may be prudent to explore further extension of the system. However, at this time it would not be a prudent investment to continue beyond the current service area."

As also discussed in Mr. Householder's testimony, "The general economic recession, unprecedented high gas prices, substantial volatility and uncertainty in gas pricing and economic downturns specific to a number of industries targeted for conversion (to natural gas) represent the primary factors for customers delaying their connections to the Pipeline." These circumstances create a situation in which the costs associated with the Pipeline project will exceed its revenues in the test year. In response to a staff interrogatory, the utility provided costs in excess of revenues for individual customers. The Company has projected that the costs associated with the Pipeline will exceed its associated revenues by $280,288.

The Pipeline project, while approved in the last case, was based on projections that remain substantially unmaterialized. We believe these unmaterialized projections represent a business risk of the Company that is more appropriately borne by its stockholders, rather than by its ratepayers. Based on the foregoing, test year revenues shall be increased by $280,288 to offset the amount that the Pipeline's costs exceed its associated revenues.

D. Total Operating Revenues

Based on the above-noted adjustments, we calculate Total Operating Revenues for the projected test year to be $38,222,074, and not the $37,873,588 projected by the utility.

E. Non-Utility Allocations

Our auditors in their testing of Operations and Maintenance (O&M) expenses found invoices for costs which properly should have been allocated to non-utility operations but were not. Audit listed these in their Audit Report as exceptions.

Because our staff had difficulty getting supporting documents from the Company in a timely manner, our staff was unable to expand some samples as much as it had wished. We have made the following adjustments to remove non-utility costs from the Company's filing:

Account 921 - Office Supplies and Expense

Office Supplies and Expense contains 100% of the rent of the Ankron Plaza Warehouse at Port St. Lucie. According to the common plant study, 28% of the use of this facility is for non-utility operations and the rent should be allocated. The adjustment to allocate the rent and trend to the projected test year is a reduction of $6,496 to Account 921. This adjustment is addressed in Audit Exception No. 16.

Account 931 - Rents

This account contains rent for the 74th Street warehouse. According to the common plant study, 23% of the use of this facility is for non-utility operations and this rent should be allocated in that percentage. The Company allocated only 16.2% of the rent through its Net Operating Income non-utility allocations. The adjustment to increase the non-utility allocation from 16.2% to 23% and trend for customer growth and inflation to the projected test year is a decrease of $8,109 to Account 931. The adjustment is addressed in Audit Exception No. 29.

Account 874 - Mains & Services

Mains and Services contains 100% of the costs associated with electricity to power three buildings which are shared and allocated to non-utility in various amounts. Since the buildings are partially used for non-utility purposes, the electricity should be allocated in the same rates as the buildings. After allocating 2002 current year costs and trending it at inflation and customer growth rates, the adjustment to allocate electricity costs to non-utility is a reduction of $19,730 to Account 874 - Mains & Service. This adjustment is addressed in Audit Exception No. 7.

Account 880 - Other Expenses

Other Expenses contains 100% of costs associated with maintenance of buildings shared by non-utility operations. The unallocated costs found include file storage, cleaning, garbage pickup, building security, and painting. Each of these costs shall be allocated to non-utility at the same rate as the buildings are. The dollar effect is a reduction to Account 880 - Other Expenses by $46,919. This adjustment is addressed in Audit Exception No. 9.

Account 921 - Office Supplies and Expense

Office Supplies and Expense in 2002 contains 100% of $1,633.84 in photocopy machine rental expenses for the Port St. Lucie/Vero office. Pursuant to our staff's review, $125.68 of this was an out-of-period payment. In our staff's review of non-utility allocations, 28% of this site is used for non-utility operations and, therefore, 28% of the copy machine rental expenses should have been charged to non-utility operations. We have removed $572 from Account 921 to reflect the non-utility use of the copy machine and to remove the out-of-period payment. This includes trending for customer growth and inflation to 2004. This adjustment is addressed in Audit Exception No. 17.

Account 921 - Office Supplies and Expense

Office Supplies and Expense also contains 100% of the cost of a Minolta copier and a maintenance contract on a Minolta copier for use in the Rockledge office building. According to the common plant study, 12% of the use of the building is for use by non-utility operations. To remove these non-utility expenses, we have reduced Account 921 by $649. This adjustment is addressed in Audit Exception No. 18.

In summary, City Gas failed to allocate certain costs in its MFR's to non-utility operations. For this reason, O&M Expense shall be reduced by $82,475 to remove non-utility expenses.

F. Odorant Costs

In the Company's last rate case, the Company included odorant costs in excess of one year in its operating expenses. We made an adjustment to odorant costs so that only one year of these costs was included in rates. In this proceeding, the Company neglected to include any odorant costs in the 2002 base year. Consistent with the findings of Order No. PSC-01-0316-PAA-GU, we have increased operating expenses by $15,007 to reflect odorant costs for the base year. Inflated for general inflation and customer growth, the 2003 amount is $15,329 ($15,007*1.021466) and the 2004 amount is $15,548 ($15,329*1.014288). A corresponding adjustment of $7,774, reducing WCA and rate base is appropriate.

G. Customer Records and Collections

Account 903 includes costs from a division of NUI, Utility Business Service (UBS). Pursuant to Audit Exception No. 13, in 2003, City Gas estimated that UBS would charge City Gas $677,521 for billing and $219,253 for payment processing. The amounts to be charged to City Gas were based on an estimated rate per bill and an estimated number of bills to prepare as well as an estimated rate per receipt and an estimated number of payments that would be processed. The billing rate also contained a 14% profit margin. The payment processing rate contained a 7% profit margin.

We have recalculated the UBS charges based on actual division costs and the actual number of bills and receipts for 2003 as contained in Audit Exception No. 13 inflated by 1.43% for customer growth and inflation. To these costs, we have added an 8.1% profit margin, the Company's requested rate of return in this proceeding. Based on this approach, which recognizes an objective profit margin that we find is reasonable for this analysis, we calculate 2004 billing costs of $585,971 and 2004 payment processing costs of $192,971, or $778,943 in total. The difference between the amount included in the Company's projected 2004 test year and our calculation is $117,831 (($677,521 + $219,253) - $778,943).

Originally, in its response to the Staff Audit Report the Company disagreed with the adjustment and stated that:

> . . . if the UBS margin is in line with market rates, there should be no disallowance. Having these services done by UBS is no different than if the services were being performed by another third party provider.

However, the Company has not provided the cost of having these services performed by a third party provider for our staff to review. For this reason, we find that it is appropriate to limit the allowable cost to the direct cost plus its requested rate of return as its profit margin.

Based on the above analysis, we have reduced Account 903 by $117,831. This adjustment will recognize a profit margin on an affiliate transaction, but limit that profit margin to the return requested by the Company in this proceeding.

H. Bad Debt and Bad Debt Rate

In its MFRs, in Account 904, the Company included Uncollectible Accounts of $1,200,000 for the historic base year 2002. For the year 2003, it projected the account for inflation and customer growth to increase by 2.48%, or $1,229,760 and for the year 2004, it projected the account for inflation and customer growth to increase by 2.32%, or $1,258,290.

For the historic base year 2002, net write-offs (bad debt write-offs less recoveries and adjustments) were $824,820. For year 2003, net write-offs were $1,070,343. On Page 13 of Witness Lopez's prefiled testimony, she says that, "The appropriate benchmark variance factor is 1.0983, reflecting the increase in the average number of customers and the increase in the average Consumer Price Index ("CPI") from the historical base year of City Gas's last rate case (1999) to the current case historical base year (2002)." Witness Lopez also states that the "bad debt expense was higher than the benchmark due in part to weakness in the economy, record high gas prices and a colder than normal winter."

In the Company's last rate case, the 1999 historic base year Uncollectible Accounts was $508,000. Applying the benchmark variance factor developed by the Company (1.0983) to the $508,000 results in the 2002 historical base year benchmark amount of $557,937, as compared to the 2002 historical amount of $1,200,000. The amount as filed, $1,200,000, is $642,063 over the benchmark amount ($1,200,000 less $557,937) in the historic test year.

In prior cases, we have tested the reasonableness of the uncollectible accounts expense by calculating a four-year average of net write-offs to revenues, excluding off-system sales. In City Gas's last rate case, this account was adjusted to reflect a four-year average of net write-offs as a percent of revenues, excluding off-system sales. A similar adjustment was made for interim purposes in this case. In a prior rate case of City Gas, in Order No. PSC-96-1404-FOF-GU, issued November 20, 1996, in Docket No. 960502-GU, <u>In re: Application for rate increase by City Gas Company of Florida</u>, this method was also used to test the reasonableness of Uncollectible Accounts, but no adjustment was made. Further, this method was used to test the reasonableness of Uncollectible Accounts in the Peoples Gas System's rate case. In Order No. PSC-03-0038-FOF-GU, issued January 6, 2003, in Docket No. 020384-GU, <u>In re: Petition for rate increase by Peoples Gas System</u>, we approved a similar adjustment to Uncollectible Accounts based on this test.

In this case, for years 2000 to 2003, the four-year average of net write-offs is $900,333 and the revenues, excluding off-system sales, is $68,262,455. Therefore, the four-year average of net write-offs to revenues, excluding off system sales is 1.3103%. Applying this rate to the 2004 projected revenues net of off-system sales of $75,341,573 results in $987,201 in projected Uncollectible Accounts for 2004 and we find that the projected test year amount for this account shall be decreased by $256,071 ($1,258,290 less $987,201 less $15,018 due to change in trend factors discussed later in this Order). This adjustment also reduces the bad debt component of the revenue expansion factor from 1.6716 to 1.3103.

It should also be noted that this adjustment is for rate making purposes only. For surveillance purposes, the Company's actual bad debt expense shall be reported.

<u>I. Advertising Expense</u>

In his direct testimony, Mr. Abramovic describes the major reasons the Company is requesting a rate increase. One of the reasons described is the Company's inability to increase its customer base at the level that was projected in the Company's last rate case. Mr. Abramovic describes the reasons for this decline in growth to include the events of September 11, the general economic downturn, recent high gas prices, and increasing competition from alternative energy sources.

One of the ways in which the Company is addressing the customer growth issue is to try to reduce customer attrition. The Company has projected an increase of $210,000 in advertising expense in Account 913 for retention programs and customer communications. The Company believes that these marketing programs will reduce customer attrition.

In general, it appears that customers benefit by an increasing customer base. Customers can realize savings through economies of scale and a larger customer base will help defray the cost of future plant projects. Likewise, customer attrition could result in higher rates from the spreading of fixed costs over fewer customers. For these reasons, a program designed to increase customer growth (or decrease customer attrition) may benefit customers. However, the cost of a program of this type should not exceed the benefit or revenue associated with the increased customers.

Based on an initial response to our staff's data request, the Company did not include the effects of these programs to retain and increase customers in its projected test year billing determinants and, therefore, revenues. City Gas responded:

> The company anticipates that the undertaking of these initiatives will retard the rate of customer attrition, but the degree to which the projected revenues can be adjusted as a result of undertaking these initiatives would be purely speculative. Also, the desired effect on customer attrition would likely not take place as early as the projected test year. These programs will be developed and introduced during the projected test year, therefore the likelihood that they will impact customers that have already made a decision to leave the system is low. Only after analysis of actual experience over time will the company be able to surmise the degree to which these initiatives affected the projected customer losses. It is very difficult if not impossible to derive with any degree of confidence an absolute measure of the number of customers retained within any given period of time as the direct result of specific marketing initiatives, but there should be a measurable decrease in customer losses

over an extended time frame, likely beyond the projected test year.

It appears that much of the benefits of the marketing programs remain largely unquantified and would be expected to take place outside the projected test year. Expenses associated with customer retention and growth programs should not be included in rates without the corresponding effects on revenues resulting from increased customer retention and growth. Further, these expenses should only be included to the extent that revenues equal or exceed the expense.

The Company later told our staff that it had built into its calculation of revenues an assumption of lower customer attrition due to this marketing program. We have addressed the effects of the assumption of lower customer attrition on billing determinants and revenues in the sections of this Order entitled Projected Total Operating Revenues and Estimated Revenues at Present Rates. We have calculated the projected test year revenues associated with the Company's assumptions to be $62,243.

Although the Company's marketing program may be successful in the long run, the revenues in the projected test year are far short of projected test year expenses due to a mismatch in costs and related benefits. We believe there are two alternatives to address this situation: 1) we could impute revenues at least equal to the expenses and include both revenues and expenses in rates; or 2) we could remove both revenues and expenses. We find that removing the marketing program expenses and revenues is the better and more straightforward approach.

We make no determination on the likely success of these programs and believe that this methodology is the better way to properly set rates. Based on the above analysis, we have reduced Account 913, advertising expense, by $210,000 to remove the cost associated with customer retention and growth programs. We have also reduced revenues to reflect the 348 customers that are projected to be lost during the test year.

J. Demonstration & Selling and Miscellaneous Sales Expense

As discussed above, we have found that the expenses associated with a new marketing program designed to retain current customers and increase new customer connections should not be allowed. Although the Company has included expenses associated with increasing customer retention and new customer connections, the Company has not fully adjusted its projected revenues to reflect the increased customer retention and new customers over the anticipated several years these programs would benefit the Company.

We also find that the cost associated with the new marketing programs included in Account 912, Demonstration and Selling Expense, and Account 916, Miscellaneous Sales Expense, shall also be excluded for the same reasons discussed above. It is important to point out that this disallowance is not meant to determine whether these programs are appropriate; rather, it is based on the matching of cost and benefits to ratepayers and whether the shareholders or the customers should bear the financial risk of the programs.

Based on all the above, we find that the appropriate amount for the Demonstration and Selling expense and the Miscellaneous Sales expense account should be the adjusted historic payroll and other expense trended forward for the test year ending September 30, 2004. We have increased the adjusted Demonstration and Selling Expense and the Miscellaneous Sales Expense by the appropriate trend factors and made the following adjustment to the projected test year ending September 30, 2004:

Demonstration and Selling Expense

9/30/04 Expense	Per MFR	Historic Trended	Adjustment
Payroll	$459,142	$311,313	($147,829)
Other	$416,247	$153,530	($262,717)
Total	$875,389	$464,843	($410,546)

Miscellaneous Sales Expense

Other	$75,784	$42,476	($33,308)

Also, as discussed above, we have decreased the projected revenue and the billing determinants for the additional customers that are projected to be lost by not implementing the marketing programs. Disallowing the marketing and customer retention programs and imputing the corresponding loss of revenues matches revenues with expenses. This approach also places the risk of the program cost on the shareholders, rather than the ratepayers.

In addition to the adjustment above, we find that an additional adjustment shall be made to Account 912, Demonstration and Selling Expenses, for the amortization expense associated with deferred piping. The Company projected amortization of deferred piping expense of $328,740 in its MFRs. According to the Company's schedule, the total deferred piping amortization expense for the year ending September 30, 2004, is $219,300. However, the Company's amortization schedule does not include deferred piping additions for the 12-month period ended September 30, 2004. In response to a staff request, the Company provided a revised deferred piping schedule. The Company estimated that additions to deferred piping would be $110,436 for the projected test year. We find this projection is reasonable based on the Company's past deferred piping additions.

We calculated the deferred piping amortization expense by amortizing the additions over ten years and applying the half-year convention (consistent with prior amortization expense). We calculated amortization expense for the additions in the projected test year to be $5,522. Therefore, projected test year deferred piping amortization expense shall be reduced by $103,918 ($219,300 + $5,522 - $328,740) to reflect our calculated amortization expense.

Later in this Order, we find that the trend rates for customer growth and inflation shall be reduced. The effect of reducing the rates reduces Account 912 and 916 by $820 and $117, respectively, shall be offset from the adjustments above to avoid double counting.

Based on the above, the projected test year Demonstration and Selling Expense shall be reduced by $513,644 ($410,546 + $103,918 - $820) and projected test year Miscellaneous Sales Expense shall be reduced by $33,191 ($33,308 - $117).

K. Office Supplies and Expenses

In its 2002 historic base year, the Company included costs of $314,691 in Account 921 related to Valley Cities Gas, an affiliate in Pennsylvania, and related to a lawsuit with City Gas's prior owner, Mr. Jack Langer. According to the Company, a receivable in this amount was set up and the contents of the portion of the receivable related to the Valley Cities Gas were not known. This receivable sat on the books for several years until it was determined that recovery was no longer a possibility and therefore there was no future benefit to this amount. According to the Company and as confirmed by its 2002 Annual Report to Stockholders, as of September 30, 2002, the Company classified Valley Cities Gas as one of it discontinued operations. Therefore, because the related costs are not recoverable, they were written off in September 2002 to Account 921.

The receivable related to the lawsuit was originally set up because the Company believed it could recover the costs related to the previous owner from its Directors and Officers' liability insurance policy. However, it was determined later that the insurance deductible exceeded the costs that could be recovered; hence, this receivable was also written off in September 2002 to Account 921.

According to our findings in the Trend Rates and Trend Basis sections below, Account 921 shall be trended on inflation only at 2.3% for 2003 and 2.0% for 2004. The 2002 amount written off trended to 2004 is $328,367 ($314,691 x 1.023 x 1.02).

These amounts are nonrecurring and Account 921, Office Supplies and Expenses, shall be reduced by $328,367 for the projected test year.

L. Charitable Contributions

On MFR Schedule G-2, Page 17 of 34, the Company included $1,919,741 in its Account 921, Office Supplies and Expense, for the Base Year 2002. Pursuant to Audit Exception No. 19, it was determined that of that amount, $201,898 was an allocation from NUI that included Charitable Contributions of $34,149. Consistent with our past practices, we find it is more appropriate for Charitable

Contributions to be borne by the stockholders, rather than the ratepayers.

According to our findings in the Trend Rates and Trend Basis sections below, Account 921 shall be trended on inflation only at 2.3% for 2003 and 2.0% for 2004. The 2002 amount of charitable contributions trended to 2004 is $35,633 ($34,149 x 1.023 x 1.02).

M. American Gas Association Membership Dues

On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In a prior City Gas rate case, the Company removed $4,045 for AGA dues for lobbying. This Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. By Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, in Docket No. 940276-GU, In re: Application for a rate increase by City Gas Company of Florida, for interim purposes, this Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the AGA (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, this Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, this Commission removed 45.10% of AGA dues.

A review of the NARUC Audit Report on AGA expenditures dated June, 2001, for the twelve-month period ended December 31, 1999, shows that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Although our staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures, approximately 40% appears to have been consistent over a number of years. Therefore, we find that 40% is representative of 2003 and 2004 expenditures, and 40% of AGA dues shall be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to our findings in the Trend Rates and Trend Basis sections below, Account 921 shall be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces our adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows our past practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, shall be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

N. Outside Services

Included in Account 923, Outside Services, is $1,232,642 for executive services allocated from NUI. Pursuant to Audit Exception No. 21, the utility failed to include several accounts in its allocated executive services including Public Affairs, Executive, Corporate Secretary, and Investor Relations expenses. Within the Public Affairs budget was $19,688 for charitable contributions. Therefore, Account 923 shall be increased by $866,569, net, to reflect the additional NUI executive services and the removal of charitable contributions as follows:

Allocated Executive Expenses 2004

R/C Dept.	Per MFR	Per Audit	Difference
001 Corp. Non-Cash Items	$1,232,642	$1,239,260	$6,618
291 Public Affairs	$0	$110,083	$110,083
401 Executive	$0	$334,585	$334,585
413 Corp. Secretary	$0	$262,637	$262,637
415 Investor Relations	$0	$152,646	$152,646
	$1,232,642	$2,099,211	$866,569

O. Injuries and Damages

In the Company's August 15, 2003 filing, the Company used a preliminary budget amount of $1,244,650 for Account 925, Injuries and Damages, (insurance) expense. This amount was based on the three-factor method which was used to allocate NUI's total insurance expense for fiscal year 2002 and fiscal years prior to that.

Pursuant to Audit Exception No. 27, NUI's October 16, 2003, insurance budget for 2004 is $5,722,774. For its updated 2004 budgets for the individual business units, NUI did not use the three-factor method. Instead, it analyzed each policy and determined a different allocation method for each policy in order to allocate the "direct cost" associated with each policy's coverage. Any cost that could not be directly charged was allocated based on the three-factor method. Having reviewed the allocation methods for the different classes of insurance policies, we find the allocation methods to be reasonable.

Of the October 16, 2003, budgeted $5,722,774 of insurance expense for NUI, $5,394,490 was charged directly to its business units. City Gas's portion of the direct charges is $839,743. The remaining $328,284 of NUI's budgeted insurance expense was allocated using the three-factor method. Under the three-factor method, City Gas's allocation is 20.7% or $67,955. Therefore, the updated budgeted amount of insurance expense for City Gas is $907,698 ($839,743 + $67,955).

Therefore, the insurance expense for the projected test year ending September 30, 2004, shall be decreased by $336,952 ($1,244,650 - $907,698) to reflect the updated amount of budgeted insurance expense and the revised method of allocating insurance expense to City Gas.

P. Employee Benefits

Pursuant to Audit Exception 28, $50,960 was trended for post-retirement medical benefits based on 2002 amounts in a subaccount to Account 926. In reviewing supporting documentation for the preliminary budget for Pension and Stock Grants, another subaccount to Account 926, post-retirement medical benefits were allocated again. Therefore, Account 926 shall be reduced by $50,960 to remove the duplicative amount.

Q. Regulatory Commission Expense

According to the Company's MFRs, the Company projected rate case expense of $425,000 in Account 928, Regulatory Commission Expense, for this proceeding. In Order No. PSC-01-0316-PAA-GU, we approved rate case expense of $339,905 to be amortized over a period of four years. The rate case expense approved in Order No. PSC-01-0316-PAA-GU, has not been fully amortized.

As outlined in the pre-filed testimony of witness Lopez, the Company requested that the current estimated rate case expense plus the unamortized balance of rate case expense from the prior rate case be amortized over a period of three years. Although we approved a four-year amortization period in the Company's prior rate case, one of the reasons cited for the period was the length of time between the Company's last rate case and the rate case processed under Docket No. 000768-GU. The time period between the filing of the current rate case and the prior rate case is three years. Therefore, we find that three years is a reasonable time period to recover rate case expense.

The Company included projected annual rate case amortization expense of $165,090 for 2004. However, the calculation of this amount was not consistent with the testimony of witness Lopez. In its calculation, the Company included the continued annual rate case amortization expense from the prior rate case plus the current rate case expense amortized over four years (rather than three) for a 9-month period. This calculation appears to have been in error, and the Company filed an updated estimate of rate case expense based on actual expense to date.

Upon review of this updated filing, we find that the estimated rate case expense shall be reduced by $45,521 for salaries and wages already included in O&M Expenses. However, primarily due to underestimated costs of noticing, we have increased rate case expense by $6,707. The remaining $386,186 of expenses incurred by the Company appear to be reasonable and prudent. Our calculation of the appropriate amortization of rate case expense is as follows:

Prior Rate Case Expense (PSC-01-0316-PAA-GU)	$339,905
Monthly Amortization	$7,081
Accumulated Amortization (March 01 - Jan. 04)	$247,835
Remaining Balance from Prior Case	$92,070
+ Current Rate Case Expense	$386,186
= Total Rate Case Expense to be Amortized	$478,256
÷ Amortization Period	3 years
= Annual Amortization Expense	$159,419

We calculated the remaining balance from the prior rate case using the monthly amortization times the number of months until the estimated date that the new rates in this case will become effective (February 2004). Amortizing the above balance by four years results in an annual expense of $119,564. The $39,855 difference in amortization expense as a result of using different amortization periods represents approximately 0.15% of O&M expense. This difference is not material. Projected test year rate case expense shall be decreased by $5,671 to reflect the annual rate case expense amortization calculated above.

Based on the above, we find that the appropriate amount of rate case expense is $478,056 to be amortized beginning February, 2004 over a period of three years with the appropriate amount to include in Account 926, Regulatory Commission Expense, to be $159,419.

R. Trend Rates

As discussed earlier in this Order, the Company provided historic data containing actual customer count data by rate class for the period October 1996 through September 2003. Based upon this data, the actual number of customers served by the Company in fiscal year 2003 was 0.15% fewer than in fiscal year 2002. Therefore, the appropriate customer growth trend factor for fiscal year 2003 is -0.15%. Also, as discussed earlier in this Order, the customer projections presented in MFR Schedule G-2, pages 6 through 11, are approved. This schedule indicates that the Company projects a -0.56% growth rate for the 2004 fiscal year. Therefore, the appropriate customer growth rate trend factor for fiscal year 2004 is -0.56%.

Regarding the general inflation rate, City Gas used 2.2% for the projected test year. This is the percentage change in the Consumer Price Index (CPI) for 2004 as forecasted by the Congressional Budget Office. This forecast was published on January 29, 2003.

However, we note that the October 1, 2003 Blue Chip Financial Forecast projects the percentage change in the CPI to be 2.0% for the four quarters of City Gas's projected test year. We find that the 2.0% general inflation rate is more appropriate because it is more current and matches the projected test year.

City Gas's payroll trend rated for the test year is 4.0%. This rate is reasonable and is approved.

S. Trend Basis

In its filing, the Company utilized three different trend factors in its calculation of the projected test year ended September 30, 2004. The three factors the Company used were a payroll rate increase, general inflation rate, and customer growth rate. For items which the Company expected significant differences from the trend factors, the Company projected expenses based on its preliminary budget or actual expense for the 12-month period ending May 31, 2003.

The Company separated each of its O&M expenses into payroll expenses and other expenses. For items that were not trended using the preliminary budget or the 12-month period ending May 31, 2003, the Company applied the payroll rate increase factor to the payroll accounts and the inflation and customer growth factor rate to the other accounts.

Account No. 886 is used to record the maintenance of structures and improvements. It would not appear that customer growth would impact the maintenance of a building, which would be a typical expense in this account. Maintenance of the distribution system would be impacted by customer growth; however, maintenance related to the distribution system is not included in this account.

Account Nos. 921 - Office Supplies, 923 - Outside Services, Account926 - Employee Benefits, and 930.2 - Miscellaneous Expense should not include an increase for the customer growth factor. These expenses are recorded under the Administrative and General Expense title, and are associated with the supplies and services for internal use. These expenses would not be impacted by customer growth. Similar expenses related directly to customers are recorded under the Customer Accounts and Collection Expense title.

Based on the above, the customer growth factor shall not be applied to the Other expense portions of O&M Account Nos. 886, 921, 923, 926, 930.2, and 931.

T. Effect of Changes on O&M Expenses

In the Trend Rates section above, we lowered the inflation rate for 2004 from 2.2% to 2.0%, and we also lowered the 2003 and 2004 customer growth rates from 0.18% to -0.15% and from 0.12% to -0.56%, respectively. By itself, the changing of the trend rates has the greatest effect on O&M expense projections.

Certain accounts used forecasted customer growth rates as well as forecasted inflation rates to project 2004 balances. However, in the section above, we have excluded the customer growth rate as a basis for projecting some of these account balances. The effect of changing the bases of the accounts has a modest effect on total O&M expense.

In setting up its O&M trend schedules, for those accounts where inflation and customer growth were used to project 2004 expenses, the Company applied the rates additively rather than multiplicatively as is our practice. For example, in their filing, 2003 accounts that were based on compound rates of customer growth and inflation were trended 2.4800% (2.3% for inflation plus 0.18% for customer growth). If done according to our prior practice, the accounts would be trended 2.4841% (2.3% X 0.18%). Calculating rates multiplicatively offers a modest increase to total O&M expenses.

Notwithstanding specific adjustments to O&M expense accounts earlier in this Order, O&M shall be reduced an additional $59,750 as a result of lowering the inflation and customer growth rates, changing the trend bases on select accounts, and recalculating the application of compound rates to be consistent with our methodology used in prior gas rate cases.

U. Total O&M Expense

Based on our adjustments above, we have reduced the Company's O&M expense for the projected test year from $24,068,151 to $22,906,546.

V. Non-Utility Depreciation Expense

During our staff's review of the Company's calculation of the depreciation expense, it was determined that the Company made an error when removing an allocation for non-utility depreciation expense. The Company inadvertently removed $115,860 from the Projected Per Books Depreciation Expense for the non-utility plant related to the Appliance Business. To correct the error, per book depreciation expense and Accumulated Depreciation - Plant-in-Service shall be increased by $115,860 to reverse the second reduction made for the Appliance Business.

W. Change in Depreciation Rate

We have recalculated the Company's projected test year depreciation expense using the new depreciation rates approved by this Commission in Order No. PSC-03-1147-PAA-GU, issued October 14, 2003, in Docket No. 030222-GU, In re: Request for approval of change in depreciation rates to be implemented as of 10/1/03, by City Gas Company of Florida. The impact of the new depreciation rates to the test year was a reduction by $243,449 to depreciation expense and $121,725 to accumulated depreciation.

X. Total Depreciation and Amortization Expense

Based on the above adjustments, we have reduced the Company's total depreciation and amortization expense for the projected test year from $8,395,317 to $7,937,786.

Y. Taxes Other Than Income Taxes

Per MFR Schedule G-2, Page 1 of 34, the Company proposes Taxes Other Than Income Taxes of $2,216,926 for year 2004. However, we have recalculated the correct amount for Taxes Other Than income to be $2,297,928, an increase of $81,002.

The Company projected 2004 Regulatory Assessment Fees (RAF) of $186,689. To calculate this amount, the Company incorrectly removed municipal utility tax, sales taxes and surtaxes from the Revenue tax basis, as well as the taxes related to Off-System Sales, Conservation Cost Expenses and Purchased Gas Adjustment (PGA) Revenues. The municipal utility tax, sales taxes, and surtaxes should not have been removed from the RAF tax basis as these taxes were not included in revenues. In addition, Conservation Revenues should have been removed instead of Conservation Expenses. We have recalculated the RAFs by applying the RAF rate of 0.005 to the Company's Total Revenue less Off-System Sales Revenues, PGA Revenues, and Conservation Revenues, resulting in RAFs of $205,815, a $19,126 increase to the Company requested amount of $186,689.

In addition, under the Clewiston Extension Revenues section of this Order, we increased revenues by $280,288, and under the Projected Total Operating Revenues section, we decreased revenues by a net amount of $86,663. The impact of these adjustments to revenues is to increase RAFs an additional $968; therefore, we have increased RAFs by a total amount of $20,094.

The Company projected 2004 Property Tax of $1,287,888 prior to its ($21,646) adjustment for non-utility taxes, resulting in the proposed amount of $1,266,242. However, in responding to a staff inquiry, the Company determined that it had neglected to include one month of property taxes in its 2004 projections. Also, our staff determined that the Company had calculated an incorrect millage rate for 2003 and applied it to 2004. In response to another staff inquiry, the Company provided actual operating results for the fiscal year ended September 30, 2003.

A review of this response shows property taxes of $1,423,549 for 2003. To this, we applied the 2% general inflation factor, resulting in projected 2004 property taxes of $1,452,020, an increase of $164,132 prior to adjustments to remove property taxes related to the appliance assets. The Company adjusted out $21,646 (or 1.68%) on Schedule G-2, Page 3, to remove appliance business property tax. However, by dividing $1,251,414 of net non-utility common plant allocated out by the Company's revised property tax basis of $71,592,632, we find that the correct percentage to remove is 1.75%. Applying this percentage to the recalculated property taxes of $1,452,020, and adjusting out $25,410 to remove appliance business property tax results in a net increase to property taxes of $160,368 ($164,132 - 25,410 + 21,646).

Additionally, having reduced Plant in Service by $144,925 to reflect inactive service lines that have been inactive for five years or more, and using a tangible property tax rate of 0.6% on these service lines, reduces property taxes by $870. The result of this adjustment and the adjustment discussed in the previous paragraph, we find that property taxes shall be $1,425,740, an increase of $159,498 to the Company requested amount of $1,266,242.

On Schedule G-7, Page 2, the Company calculated projected payroll taxes of $676,114 using an eight percent effective rate and a payroll tax basis of $8,451,425. The $8,451,425 was actually backed into by extracting the payroll taxes from individual responsibility centers and dividing them by the eight percent rate. Pursuant to Audit Exception 30, further analysis, and discussions with the Company, it was determined that the actual payroll tax basis was less than the $8,451,425 because the Company had allocated $1,073,947 of payroll and other costs, including payroll taxes, out to Elizabethtown Gas. The $1,073,947 consisted of payroll of $913,515 and other costs of $160,432, so that the payroll taxes associated with the $913,515 of payroll was removed twice: once when the payroll taxes were allocated from Taxes Other Than Income to Account 903 with the payroll allocated to that account and again when the payroll, payroll taxes, and other benefits were allocated to Elizabethtown. To match the payroll taxes with the payroll included in O&M expense, we have used the 2004 projected payroll shown on Schedule G-2, Page 19, of $6,305,531 and increased it by $913,515, to $7,219,046 to calculate a corrected payroll tax basis. Payroll taxes of eight percent were then calculated on the $7,219,046, a total of $577,524. Therefore, Payroll Taxes shall be $577,524, a $98,590 decrease to the Company requested amount of $676,114.

In summary, based on the above adjustments, Taxes Other Than Income shall be decreased by $98,590 for payroll taxes, increased by $20,094 for RAFs, and increased by $159,498 for property taxes, resulting in a net increase of $81,002 and a net amount of Taxes Other Than Income of $2,297,928. A table of our calculations is set out below:

	Per Books	Company Adjustments	Company Adjusted	Commission Adjustment	As Adjusted
Payroll Taxes	$ 676,114		676,114	(98,590)	577,524
RAFs	357,163	(170,474)	186,689	20,094	206,783
Property Tax	1,287,888	(21,646)	1,266,242	159,498	1,425,740
Use Tax	88,961		88,961	0	88,961
Sales Tax Disc	(1,080)		(1,080)	0	(1,080)
TOTAL	$ 2,409,046	(192,120)	2,216,926	81,002	2,297,928

Z. Income Tax Expense

The Company proposes to include ($403,763) of income tax expense for its 2004 projected test year. However, our adjustments to revenues and expenses increases tax expense by $709,935. Also, our adjustments to the Company's capital structure and rate base results in an increase of $52,108 to the interest reconciliation adjustment. The net result of these adjustments is an increase of $762,043 to income tax expense. Therefore, the appropriate amount of income tax expense, including current taxes, deferred income taxes, and interest reconciliation is $358,280.

AA. Total Operating Expenses

Based upon our adjustments set out above, the appropriate amount of Total Operating Expenses for the projected test year is $33,500,540, and not the $34,276,631 amount calculated by the Company.

BB. Net Operating Income

Based on all the above, the appropriate amount of Net Operating Income for the projected test year is $4,721,534, and not the $3,596,957 amount calculated by the Company. Our calculation of Net Operating Income is shown on Attachment 3.

VII. REVENUE REQUIREMENTS

A. Revenue Expansion Factor

The Company calculated a Revenue Expansion Factor of 0.610156 and a Net Operating Income Multiplier of 1.6389. We calculate a revenue expansion factor of 0.612409 and a net operating income multiplier of 1.6329. The only difference between the Company's calculation and our calculation is the Bad Debt Factor, which the Company included at 1.6716%, and which we calculated earlier in this order to be 1.3103%. Our calculations of the appropriate Revenue Expansion Factor and Net Operating Income Multiplier are shown on Attachment 4.

B. Annual Operating Revenue Increase

The appropriate annual operating revenue increase for the projected test year is $6,699,655, and not the $10,489,305 requested by the Company. Our calculations of the appropriate revenue increase are shown on Attachment 5.

VIII. COST OF SERVICE AND RATE DESIGN

A. Estimated Revenues at Present Rates

Per MFR Schedule H-1, Page 10, the Company shows present revenue from sales of gas for the projected test year of $36,957,273. Our calculation of projected revenues based on the projected billing determinants results in a total of $36,926,619, which is $30,654 below what the Company filed.

Based on our decision to not allow the costs of the Company's proposed marketing programs, we reduced projected total operating revenues by $62,243, which represents the projected revenues attributable to the 348 customers that would otherwise have been retained and taken service in the GS-100 rate class. However, due to two errors in the Company's calculation of projected total operating revenues, we made adjustments to the estimated revenues for the GS-120K and GS-250K rate schedules in the amounts of $33,684 and ($2,095), respectively, for a total error of $31,589.

Our correction of the $31,589 error and the reduction in revenues of $62,243 to reflect the adjustment to projected customers and therm sales attributable to the customer retention programs results in a total recommended decrease of $30,654. With these adjustments, City Gas has accurately applied the tariffed rates to the billing determinants for the test year.

B. Cost of Service Methodology

Our calculation of the appropriate cost of service methodology to be used in allocating costs to the various rate classes is reflected in the cost of service study included in Attachment 6, pages 1-16. The study reflects our adjustments to rate base, operations and maintenance expense, net operating income and projected test year base rate revenues.

C. Customer Charges

The customer charge is a fixed charge that applies to each customer's bill, no matter the quantity of gas used for the month. The customer charge is typically designed to recover costs such as metering and billing that are incurred no matter whether any gas is consumed.

Our approved customer charges are contained in the table below. The table also shows the existing customer charges and the Company-proposed charges.

Rate Class	Present Residential Charge	Present Commercial Charge	Company Proposed Charge	Commission Approved Charge
GS-1	$7.50	$20.00	$9.25	$8.00
GS-100	$7.50	$20.00	$12.00	$9.50
GS-220	$7.50	$20.00	$15.00	$11.00
GS-600	$7.50	$20.00	$20.00	$12.00
GS-1,200	$7.50	$20.00	$25.00	$15.00
GS-6,000	-	$20.00	$33.00	$30.00
GS-25K	-	$20.00	$130.00	$80.00
GS-60K	-	$20.00	$185.00	$150.00
GS-120K	-	$50.00	$300.00	$250.00
GS-250K	-	$100.00	$500.00	$300.00
GS-1,250K	-	$250.00	$800.00	$500.00
Gas Lighting	N/A	N/A	N/A	N/A
Natural Gas Vehicles	-	$15.00	$15.00	$15.00
Contract Demand	-	$400.00	$400.00	$400.00

As shown in the table, we have approved customer charges that are generally lower than what the Company requested. This was due in part to concern that large increases in the customer charge would result in large percentage increases in some bills, particularly for low-use residential and small commercial customers. These approved charges are also based on the customer costs developed in the cost of service study.

D. Distribution Charges

Our approved per therm Distribution Charges are contained in Attachment 7.

E. Miscellaneous Service Charges

The table below shows City Gas's present charges, the charges it has proposed, and our approved charges. We have discussed the Company's proposed temporary disconnect charge later in this Order.

Type of Miscellaneous Charge	Present Charge	Company-Proposed Charge	Commission Approved Charge
Residential Connect	$30.00	$50.00	$50.00
Non-residential Connect	$60.00	$110.00	$110.00
Residential Reconnect after non-payment	$30.00	$50.00	$37.00
Non-Residential Reconnect after non-payment	$60.00	$170.00	$80.00

Change of Account	$20.00	$20.00	$20.00
Customer Requested Temporary Disconnection	Proposed new charge	$20.00	Disallowed
Bill Collection in lieu of Disconnection	$15.00	$20.00	$20.00
Late Payment Charge	1.5%	> of $5.00 or 1.5%	> of $5.00 or 1.5%
Returned Check Charge	> of $25.00 or 5%	> of $25.00 or 5%	> of $25.00 or 5%
Copy of Tariff	$25.00	$25.00	This charge shall be eliminated.

We have approved charges that differ from the company-proposed charges for the Residential Reconnect After Disconnect for Non-payment and the Non-Residential Reconnect after Disconnect for Non-payment charges. The Company proposed a charge of $50 for residential customers who are reconnected following disconnect for cause. We have reduced this charge by $13 to reflect the cost of a new regulator that City Gas included in its proposed charge. City Gas indicated that when a customer is disconnected for non-payment, the regulator is removed and cannot be reused, thus requiring the installation of a new one when service is restored. However, our safety engineers say that this is not always the case. While the regulator is sometimes removed in such situations, there is no safety or other reason why the removed regulator cannot be returned to inventory and reused. We therefore find that it is not appropriate to include the charge for a new regulator in the residential reconnect fee.

The Company has proposed a charge of $170 for non-residential customers who are reconnected following disconnect for cause.

Based on the same reasons set out above, we have reduced this charge by $90 to reflect the cost of a new regulator that City Gas included in its proposed charge.

We have also eliminated the charge for obtaining a copy of the Company's tariff. Currently, the Company's tariff contains a charge of $25 for this activity. The Company is not proposing a change to this charge, and did not submit any data regarding the current cost for this service. In response to inquiries by our staff, the Company indicated that it had not developed any cost data. In addition the Company did not project any revenues associated with this change for the test year. Because there is no cost support for this charge, we find that the charge shall be eliminated. The entire tariff is available to customers on the Company's website, and copies are available from this Commission at minimal cost.

F. Revenue Allocation Across Rate Classes

Our allocation of the revenue increase is contained in Attachment 6, page 16 of 16, and allocates a $6,699,655 revenue increase among the rate classes, as shown in column 7.

This allocation includes the $280,288 in imputed revenues for the Clewiston expansion. As shown on Attachment 6, page 15 of 16, the total target revenues which rates were designed to recover were reduced by this amount on a pro rata basis by rate class based upon the approved increase. No increase was allocated to the Contract Demand class because customers in this class have entered into special contracts.

The allocation of the increase was designed to move each rate class towards the system rate of return (i.e., to parity), while taking into account the rate impact on each customer class.

G. Rate Structure

Prior to this filing, City Gas defined its rate classes in part based on the end uses of the customers in the class. For example, all of City Gas's residential customers currently take service under a single residential rate schedule that is not available to non-residential customers. Similar distinctions are made among the non-residential rate schedules for commercial and industrial customers.

In this filing, City Gas proposes to restructure its rates in order to group customers based solely on the number of therms they use in a year. This restructuring will result in eleven new rate schedules. These therm usage threshold levels are designed to more accurately reflect similar patterns such as annual volume, load profile, and the assignment of fixed and variable costs, in order to effect a more equitable distribution of the costs of serving the various rate classes. We have recently approved similar gas rate restructuring for both the Florida Division of Chesapeake Utilities Corporation and Indiantown Gas Company.

Under the proposal, City Gas residential customers will now take service under one of 5 new volumetric rate classes, depending on how many therms they use annually. For example, customers (both residential and non-residential) who use less than 100 therms per year will take service under the GS-1 rate schedule. Those who use between 101 and 219 therms per year will be served under the GS-100 rate. Small Commercial Transportation (SCT) and Commercial and Industrial Service (CS) customers will be migrating to one of eight volumetric rate schedules.

City Gas currently divides its transportation and sales service customers into separate rate schedules. The proposed restructuring would consolidate all of its customers into volumetric-based rate schedules that will serve both transportation and sales service customers, as discussed later in this Order.

We find that the proposed replacement of existing rate classes with volumetric-based rate classes yields a more equitable distribution of the costs of serving various customer classes. Additionally, the revised therm usage threshold levels in the rate classes more accurately reflect similar use patterns such as annual volume, load profile, and the assignment of fixed and variable costs. For these reasons, we find that the proposed volumetric-based rate classes are appropriate and they are approved.

H. Minimum Bill Provision

City Gas has proposed a minimum bill provision for customers using 60,000 therms or more per year. Specifically, if the annual therm usage of a customer falls below the annual minimum qualifying therms specified in the rate schedule the customer takes service under, then City Gas proposes to apply the distribution charge to the difference between the actual annual usage of the customer and the minimum qualifying therms.

To illustrate, in order to qualify for service under the GS-60K rate schedule, the customer must use at least 60,000 therms per year. Once a year, City Gas will reassess each customer's eligibility for the GS-60K rate based on their annual usage. If a customer's usage for the previous 12-month period falls below 60,000 therms, e.g., 50,000 therms, the customer will be assessed a bill that applies the distribution charge to 10,000 therms. The 10,000 therms represent the difference between the actual annual usage of the customer and the annual minimum qualifying therms for the GS-60K rate. For the following 12-month period, the customer in the above illustration will have a choice of reclassification to the appropriate rate schedule or continue to take service under the GS-60K rate.

City Gas is currently applying a minimum annual bill provision to transportation customers using over 120,000 therms per year. We find that a minimum annual bill sends the appropriate price signal to customers to take service under the applicable rate schedule, based on actual usage. Therefore, City Gas's proposal to apply a minimum annual bill to customers using 60,000 or more therms per year is approved.

I. Competitive Rate Adjustment Rider

The Competitive Rate Adjustment (CRA) allows City Gas to recover from its customers any revenue shortfall or credit any revenue surplus it incurs by offering a discount to large volume customers that have alternate fuel capabilities. To be eligible for the alternate fuel discount, customers must demonstrate the ability and intent to physically bypass the Company's distribution system or to use alternative fuels. City Gas has the discretion to discount the non-gas distribution charge to a level necessary to retain the customer. Similarly, when market conditions allow, City Gas can increase the distribution charge. Determination of the alternate fuel discount is based on a Commission-approved formula which is driven by the price of the alternate fuel relative to the price of natural gas.

Customers with alternate fuel capabilities currently take service under the contract interruptible rate schedules CI, CI-TS, CI-LV, and CI-LVT, and are not assessed the CRA. In addition to the contract interruptible customers, customers taking service under City Gas's interruptible rate schedules IP, ITS, IL, and ILT are not assessed the CRA, even though these customers are not eligible for the alternate fuel discount. The interruptible rates are available to customers that use a minimum of 250,000 therms per year.

City Gas calculates the shortfall or surplus by comparing actual revenues received from customers receiving the alternate fuel discount to revenues City Gas would have received in the absence of the alternate fuel discount. City Gas collects the shortfall or refunds the surplus to its customers through the CRA charge, on a cents per therm basis. The CRA charge is adjusted annually in September.

As stated above customers taking service under the IP, ITS, IL, and ILT rates currently do not pay the CRA, even though they are not eligible for receiving an alternate fuel discount. However, as discussed above in the Rate Structure section of this Order, we have redefined City Gas's rate classes solely based on annual therm usage and eliminated the distinction between firm and interruptible service. In addition, as discussed below, City Gas has proposed to apply the Alternate Fuel Discount as a Rider. As a result, customers who are currently on interruptible rate schedules IP, ITS, IL, and ILT, will be billed the CRA under the City Gas proposal. Customers that demonstrate a viable economic alternative to taking service from City Gas will continue to be eligible for the alternate fuel discount, and will not be assessed a CRA.

We find that City Gas's proposal to apply the CRA to all customers except those whose rates are set in response to market pressures is appropriate, and shall be approved. The alternate fuel discount helps insure the retention of industrial load, and the associated cost should be borne by all customers. In the interest of fairness, large-volume customers that do not have alternative fuel capabilities should not be excused from paying a CRA.

J. Demand Charge

City Gas's Proposed Demand Charge

City Gas has proposed to apply a demand charge of $0.725 to customers taking service under proposed rate schedules GS-60K, GS-120K, GS-250K, and GS-1,250K. Currently, there are 157 accounts taking service under these rate schedules. The demand charge would apply in addition to the customer charge and the per-therm distribution charge.

Currently, no retail investor-owned natural gas utility in Florida includes a separate demand charge in its rate design. Traditional base rate design for these utilities includes only a fixed monthly customer charge and a variable non-gas energy or distribution charge.

City Gas has proposed a new billing determinant for the application of the demand charge. City Gas has proposed to apply the demand charge of $0.725 to the customer's actual single highest daily therm usage, or Demand Charge Quantity (DCQ), over a historical period of up to three years. The DCQ will remain unadjusted for a 12-month period. City Gas has proposed to reset the DCQ for each customer annually in August. The proposed tariffs also included a provision that allowed the Company to increase a customer's DCQ if their highest daily usage exceeds the Company's assigned DCQ more than three times during a 12-month period.

Customers on rate schedules GS-120K, GS-250K, and GS-1,250K have automatic meter reading (AMR) devices that record the customer's actual daily therm consumption. As a result, the DCQ for these customers would be based on the highest actual daily therm consumption recorded by the AMR. However, customers on rate schedule GS-60K are not required to have AMRs. For these customers, City Gas has proposed to estimate the DCQ based on the highest monthly usage for the most recent three-year period, divided by the number of days in the month.

City Gas asserts that few capacity costs are dependent on gas throughput, and that the majority of these costs are fixed, i.e., costs that are incurred whether the customer uses any gas or not. City Gas further notes that large customers are accustomed to demand charges from their electric provider. Capacity costs include the cost of mains and the associated O&M cost, depreciation, and return.

The proposed demand charge is designed to recover a portion of the annual capacity costs the Company incurs to serve the four rate classes listed. Specifically, the demand charge is designed to recover the peak capacity costs City Gas incurs during the winter months. City Gas states that allocating the total annual capacity costs would result in an excessive demand charge that would result in a considerable adverse reaction from customers. Any capacity costs that are not recovered through the demand charge will be recovered through the per-therm distribution charge.

Analysis of the Proposed Demand Charge

It is important to note that City Gas's proposal does not increase the revenue requirement for rate schedules GS-60K, GS-120K, GS-250K, and GS-1,250K. Rather, it is a rate design issue only. It does, however, affect customers within each of the four rate schedules differently, depending on their usage patterns.

Pursuant to a request by our staff, City Gas performed an analysis showing the impact on each of the 157 customers affected by City Gas's proposal. City Gas provided a base rate bill comparison for each customer showing: (1) the total annual bill including the $0.725 demand charge, and (2) the total annual bill if all capacity costs were recovered through the distribution charge, i.e., the demand charge is zero.

The analysis shows that while some customers benefit from the proposal, numerous customers would receive a significantly higher bill under a rate design that includes the proposed demand charge of $0.725.

One customer that would be negatively impacted by this proposal addressed our staff at the customer meeting held in Port St. Lucie on October 30, 2003. The customer stated that his therm usage is seasonal, with very high usage during the winter months, and little or no usage during the summer months. The customer stated that he currently pays only the customer charge during the summer months. However, under City Gas's proposal, the customer would see a significant increase in his bills during the summer months. The customer would pay a demand charge amount that would be determined by the maximum daily usage that occurred during the winter.

As City Gas asserts, it is correct that the demand charge is a familiar concept for commercial customers in the electric industry. However, in the electric industry the demand charge is applied to the customer's measured maximum kilowatt (kw) demand during each billing month. Any fluctuation in a customer's monthly kw demand will be reflected in the monthly bill. Under City Gas's approach, no consideration is given to the fact that customers' therm usages can vary on a monthly basis.

We also note that City Gas has proposed to apply the demand charge to customers taking service under the GS-60K rate. However, the customers taking service under this rate are not required to have AMR devices that record their daily usage. Without an AMR device at the customer's premises, City Gas can only record the customer's monthly usage. As stated earlier, for customers without an AMR device, City Gas has proposed to set the DCQ equal to the highest monthly usage for the most recent three-year period divided by the applicable number of days in the month. This approach yields only an estimate of the customer's actual highest daily usage, and we find that it should therefore be rejected.

<u>Commission Approved Demand Charge</u>

We find that the concept of a demand charge is appropriate for the gas industry. However, in light of the fact that the concept is new to Florida's gas customers, we believe that great consideration must be given to customer acceptance.

Our development of a demand charge of $0.289 is shown in Attachment 8, and is based on several discussions our staff had with the Company. The approved demand charge does not modify the total base rate revenues City Gas is projected to receive from the customer classes that will be billed a demand charge. By approving a lower demand charge, we have increased the distribution charge accordingly.

Our demand charge includes three modifications to City Gas's proposal. First, upon the suggestion of the Company, we have included only the return and depreciation components of the capacity costs to be recovered through the demand charge. This methodology lowers the total dollar amount the demand charge is designed to recover, and in turn lowers the demand charge. Under City Gas's proposal, the demand charge was designed to recover $2,013,737 in winter peak capacity costs. As can be seen in Attachment 8, our demand charge recovers $771,039 in winter peak capacity costs.

Secondly, we find that the applicability of the demand charge shall be limited to customers that have AMR devices. Customers with AMR devices take service under rate schedules GS-120K, GS-250K, and GS-1,250K. Since customers on the proposed GS-60K rate currently are not required to have AMR devices, we find it is not appropriate to apply a demand charge to them.

Finally, a separate DCQ shall be established for the winter season (November through March) and for the summer season (April through October). This approach reflects how City Gas is billed for capacity from the Florida Gas Transmission Company (FGT) under its Firm Transportation Service (FTS-1) tariff, which allows City Gas to contract for separate pipeline capacity in the winter season and in the summer season. FGT's rate is the same for both seasons. The two seasons reflect the fact that the volume of gas City Gas transports on FGT's pipeline differs significantly between the winter and summer seasons.

City Gas filed revised tariffs that include a provision that the Company will not increase a customer's DCQ unless the customer has had at least three occurrences of DCQs in excess of their current DCQ within the 12-month period ending July of the current year. We find that the proposed tariff revision is appropriate. City Gas shall revise its tariff to include the above provision to apply to the seasonal periods.

Conclusion

For the reasons set out above, City Gas's proposed demand charge is modified as indicated above and as shown on Attachment 8.

K. Interruptible Rate Classes

City Gas currently provides service to large volume sales and transportation customers under interruptible rate schedules IP, CI, ITS, CI-TS, IL, CI-LV, ILT, and CI-LVT. The current tariff for the above rates includes provisions stating that gas deliveries may be curtailed or interrupted at the discretion of City Gas. Concurrent with City Gas's proposal to replace its existing rate classes with 11 new volumetric-based rate classes, the Company has proposed to eliminate the distinction between interruptible and firm rate classes.

City Gas asserts that interruptions in recent years have been infrequent, and therefore interruptible load does not provide any benefits to the operational integrity of the system. From 1998 to the present, City Gas has interrupted customers four times. The causes of each of these interruptions were force majeure events that occurred on the Florida Gas Transmission's (FGT) interstate pipeline system, such as a fire caused by a lightning strike on an FGT compressor station and Tropical Storm Isidore that affected production in the Gulf of Mexico.

The four recent interruptions affected customers taking service under both interruptible and firm rate schedules. During periods of supply shortages, operational constraints, or force majeure events, City Gas implements the terms of its Gas Curtailment Plan (plan). The plan establishes procedures for City Gas to implement during interruption periods. Under the plan, customers that provide services for the protection of public health or safety, such as hospitals or wastewater facilities, continue to receive gas service during an interruption period, regardless whether they take service under a firm or interruptible rate.

Because the curtailment plan and not the tariffs determine which customers are interrupted, we find that City Gas's proposal to eliminate the distinction between interruptible and firm rate schedules is appropriate, and it is approved. The proposal is also consistent with City Gas's proposed customer classes that are solely based on annual therm usage.

L. Alternate Fuel Discount (AFD) Rider

The Alternate Fuel Discount (AFD) is a rate reduction offered to large customers who have the capability to use an alternate fuel source at a lower equivalent cost than natural gas. Currently, the AFD is available to sales and transportation customers in the Contract Interruptible and Contract Interruptible Large Volume rate classes. Customers must provide quarterly certification of their alternative fuel capability to continue to receive the discount.

City Gas has not proposed any substantive changes to the AFD mechanism; however, it has proposed to offer the AFD as a separate rider that will be available to customers in the proposed new GS-120k, GS-250k and GS-1,250k rate classes. We find that this change is appropriate, and it is approved.

M. Alternate Fuel Capability

The Alternate Fuel Discount (AFD) is a rate reduction offered to large customers who have the capability to use an alternate fuel source at a lower equivalent cost than natural gas. Currently, the AFD is available to sales and transportation customers in the Contract Interruptible and Contract Interruptible Large Volume rate classes. Customers must provide quarterly certification of their alternative fuel capability to continue to receive the discount. To take service under the Contract Interruptible rate classes, customers must use a minimum of 250,000 therms per year. Customers taking service under the Contract Interruptible-Large Volume rate class must use a minimum of 1,250,000 therms per year.

The Company proposes to lower the threshold to qualify for the AFD from a minimum of 250,000 therms per year to customers using a minimum of 120,000 therms per year. The AFD will now be available to customers in the proposed new GS-120k, GS-250k, and GS-1,250k rate classes. Lowering the threshold will enable the Company to more effectively retain load by making the AFD available to more customers. The Company states that the lowering of the threshold will enable two additional existing customers to qualify for the AFD.

We find that the proposed lowering of the threshold is appropriate, and it is approved. Lowering the threshold will better enable City Gas to retain at-risk customers who make a contribution to fixed costs that might otherwise be borne by the general body of ratepayers.

N. Transportation Customers

Sales customers receive their gas supply directly from City Gas. Transportation customers arrange for the purchase of their gas through a marketer or third party supplier for delivery to City Gas's system, and City Gas provides only the transportation of the gas to the customer. City Gas has been offering transportation service to all of its non-residential customers since 1999.

City Gas's tariff currently has separate rate schedules for sales and transportation customers. For example, the Large Commercial Service (LCS) rate is applicable to sales customers using a minimum of 120,000 therms per year, while the Commercial Transportation Service (CTS) rate is available to transportation customers using a minimum of 120,000 therms per year. The per therm distribution charge is the same for transportation service as that under the otherwise applicable rate schedule for sales service. However, the rate schedules for transportation service contain a higher customer charge to recover certain costs associated with offering transportation service. In addition to the base rate charges, sales customers are responsible for the Purchased Gas Adjustment (PGA) charge, which does not apply to transportation customers because they purchase their own gas.

City Gas has proposed to consolidate its tariffs into a single set of rate schedules that would be applicable to both sales and transportation customers. Customers electing either sales or transportation service would be served under the same rate schedule based on annual therm usage, and therefore pay the same customer charge, distribution charge, and demand charge when applicable. As under the existing tariffs, sales customers will also pay the PGA charge. As discussed below in the Third Party Suppliers section of this Order, City Gas has proposed to recover all transportation-related costs from the third party supplier rather than from the customer.

We find that the Company's proposal to consolidate its sales and transportation customer classifications is appropriate, and it is approved. Consolidation will simplify the administration of City Gas's rate schedules and other tariff provisions.

O. Standby Sales Service

Standby Sales Service is an optional service that transportation customers can purchase that makes a specified amount of gas available in the event of an emergency or failure of their third-party gas supplier to supply gas. The customer pays a Monthly Standby Charge of $0.785 per therm of the maximum daily standby service requested. This charge is paid whether the customer requests gas under standby sales service for that month or not. If customers require gas under the service, they must provide 24 hours' notice and pay the weighted average commodity cost of gas plus all billing adjustments, taxes, and an administrative charge of $0.03 per therm.

City Gas proposes to discontinue the service due to lack of use. A response to our staff's data requests indicates that Standby Sales Service has not been utilized by any City Gas customer for the past five years. The Company stated that its customers were reluctant to pay the monthly standby charge throughout the year for a service that was rarely if ever used.

Because the service has not proven useful to customers as evidenced by their lack of participation, we find that the Standby Sales Service shall be eliminated. Third party suppliers who require an emergency supply of gas can take service under the Company's proposed new Transportation Supply Service rate schedule set out below.

P. Transportation Supply Service

Transportation Supply Service (TSS) is a proposed new option offered to Third Party Suppliers (TPSs) who sign a service agreement with City Gas. TPSs are marketers, brokers, and other third party suppliers that act as agents for customers who take Transportation Service from City Gas.

TSS is intended to supply transportation customers with gas on the rare occasions when the TPS is unable to do so. The service involves only the provision of gas. The customer's base rate charges paid to City Gas for transportation still apply. TSS does not provide a guaranteed supply of gas. City Gas provides the emergency supply of gas to a customer only if it is available.

Under the TSS, the customer pays an annual charge of $500 when service is initially requested, a daily usage charge of $50, and a commodity rate per therm of gas used charge of the higher of either the purchased gas adjustment or the incremental cost of purchase or production, plus an adder of $.075 per therm. Customers only pay the charges associated with the service if they utilize it.

Under the Special Provisions section of the proposed tariff, the Company includes the following language:

> 3. Pricing Modification: the methodology and pricing set forth in the Charge section of this Rate Schedule may be modified if agreed to by the TPS and the Company, in order to accommodate market conditions or special Customer requirements.

We find that this provision is not appropriate. Because the Company is proposing rates for TSS that will be approved by this Commission and included in its tariff, the Company is required to file for Commission approval for any change in the rates charged under the tariff. Therefore, this provision shall be excluded from the proposed TSS rate schedule.

The proposed TSS rate schedule provides a mechanism to allow the Company to provide gas, when available, to transportation customers in the rare instances when a TPS is unable to do so. With the exception of the Special Provision discussed above, we find that the TSS rate schedule is an appropriate offering, and it is approved.

Q. Temporary Disconnect Charge

The proposed new Temporary Disconnect Charge would be applied when a customer requires disconnection on a short-term basis, such as for pest extermination or home renovation. The Company has proposed a charge of $20 for this service. When the customers request that service be reconnected, they are then assessed the proposed $50 connection fee, resulting in a total cost of $70.

Upon analysis of the Company's proposal, we are concerned with the disparate impact of the proposed charge on the Company's customers. Customers who require reconnection of their service after disconnection for cause would pay only the approved reconnection charge of $37. This charge does not include any of the costs of disconnection. Customers in good standing who request temporary disconnection thus would have to pay more to have their gas temporarily disconnected and reconnected than a customer whose gas was turned off for non-payment ($70 vs. $37). We do not believe that this is equitable.

In addition, City Gas did not include any revenues associated with the implementation of this charge in its MFRs. For these reasons, we find that the Company's proposed Temporary Disconnect Charge should not be approved.

R. Daily Imbalance Charges

The Daily Imbalance Charges apply to Third Party Suppliers (TPSs). TPSs obtain natural gas for customers and deliver it to City Gas via the Florida Gas Transmission (FGT) interstate pipeline. City Gas then transports the gas from the interstate pipeline to the customers. A customer who obtains gas for itself in this manner is also considered a TPS.

City Gas reserves the right to require daily balancing that the Company reasonably determines is necessary for operational reasons. In all instances, City Gas will provide the TPS with at least twenty-four hours advance notice that daily balancing will be imposed. This daily balancing insures that the TPS delivers the appropriate quantity of gas from the interstate pipeline to City Gas for transportation to the TPSs' customers during times when there are operational constraints on the interstate pipeline.

City Gas proposes to apply the Daily Imbalance Charges to encourage TPSs to make required gas deliveries within a five percent threshold above or below their required amounts during periods of operational constraints. When the TPSs fail to operate within the threshold, the charges apply. These charges are intended to offset the cost of the penalties that City Gas is required to pay to FGT for imbalances on the interstate pipeline, and are only assessed if City Gas is required to pay a penalty to FGT. All revenues collected from the Daily Imbalance Charges are credited to all of City Gas's sales customers through the Purchased Gas Adjustment Clause.

A review of the derivation of the Daily Imbalance charges shows that they are appropriate to encourage TPSs to make requisite natural gas deliveries during periods of constraint on the interstate pipeline. Therefore, they are approved.

S. Third Party Suppliers

City Gas currently recovers the additional cost to provide transportation service through a higher customer charge for transportation service than for the otherwise applicable sales service. City Gas has proposed to recover the cost to provide transportation service from the TPSs instead of the transportation customers. Specifically, City Gas has proposed two new monthly charges applicable to TPSs: (1) a $400 customer charge, and (2) a $5.92 charge for each transportation customer served by the third party supplier.

TPSs wishing to deliver natural gas to the Company's distribution system for transportation customers must sign a contract with the Company pursuant to the Third Party Supplier (TPS) tariff. The TPS tariff currently provides the terms and conditions that marketers must meet in order to provide transportation service. City Gas has proposed to include the two new monthly charges in the TPS tariff.

The proposed monthly third party supplier customer charge of $400 is designed to recover $52,808 in projected annual gas control administration costs from eleven projected TPSs. These costs include the salary and computer costs of two employees that track nominated and actual TPS gas deliveries on a daily basis.

The proposed monthly charge of $5.92 for each transportation customer served by the TPS is designed to recover $145,462 in projected annual billing and programming costs. City Gas is forecasting that 2,048 customers will receive transportation service in 2004.

Upon review, we find that the proposed new monthly charges applicable to TPSs are reasonable and they are approved. The proposed charges will ensure that the cost of providing transportation service is recovered from the marketers, and ultimately from the transportation customers, and not from City Gas's sales customers.

T. Unauthorized Gas Use Provision

City Gas has proposed a new Unauthorized Gas Use provision that applies when a curtailment or interruption notice is issued by City Gas, this Commission, or any other agency having jurisdiction. If a customer continues to use gas after being notified that a curtailment or interruption exists, the customer is billed at the higher of $2.50 per therm or a rate equal to ten times the highest price, for each day, for gas delivered to the Florida Gas Transmission hub at St. Helena Parish. The Unauthorized Gas Use Provision also applies to TPSs who fail to deliver gas in the quantities or imbalance ranges specified in the proposed TPS rate schedule.

The purpose of the provision is to create a disincentive for customers to use gas during periods of curtailment or interruption on the interstate pipeline, and to create a disincentive for TPSs to fail to deliver gas for their customers. Any penalties paid under this provision are credited to the Company's Purchased Gas Adjustment clause, and therefore benefit the ratepayers.

We find that the proposed provisions are a reasonable method to insure that customers comply with curtailment orders and that TPSs meet their commitments to deliver gas for their transportation customers.

U. Contract Transportation Service (KTS) Rate Schedule

This Commission approved City Gas's Contract Transportation Service (KTS) in Order No. PSC-00-1592-TRF-GU, issued September 5, 2000, in Docket No. 000717-GU, In re: Petition for authority to implement contract transportation service by City Gas Company of

Florida. The KTS tariff applies to new and existing commercial transportation customers who add 250,000 therms per year of incremental load, and is designed to meet City Gas's needs to compete for potential customers who have viable alternative energy options. The negotiated transportation charge may not be less than $0.01 per therm and can not be set lower than the incremental cost the Company incurs to serve the customer. The KTS rate applies only to the incremental load. One customer currently takes service under this rate.

City Gas has proposed to rename the KTS rate, which would now be called Contract Demand Service (KDS), and to expand the rate to include customers taking both transportation and sales service. This proposed change is consistent with the Company's proposal to consolidate its sales and transportation customer classification, and is approved.

V. Effective Date for Revised Rates and Charges

All new rates and charges shall become effective for meter readings on or after 30 days from the date of our vote on January 20, 2004. This will insure that customers are aware of the new rates prior to being billed for usage under the new rates.

IX. OTHER ISSUES

A. Interim Increase Refund

In this docket, the requested interim test year was the twelve months ended September 30, 2002, and we granted the interim increase by Order No. PSC-03-1217-PCO-GU, issued October 27, 2003.

Any interim increase is reviewed when final rates are derived to determine if any portion should be returned to the ratepayers. In this case, interim rates went into effect November 26, 2003, two months after the beginning of the 2004 projected test year and will continue for another three months of the projected test year before final rates are scheduled to take effect. Since the period interim rates are in effect is well within the projected test year for determining final rates, the rate case review requirements are appropriate for affirmation of the interim increase.

No refund of interim rates is required because the increase approved for the projected test year exceeds the interim increase awarded.

B. Required Entries and Adjustments

As a result of our findings in this rate case, City Gas shall file, within 90 days after the date of the final order in this docket, a full description of all entries or adjustments that will be either recorded or used in preparing its annual report, rate of return reports, and books and records which will be required.

C. Energy Conservation Cost Recovery Factors

Conservation cost recovery factors are dependant on the final rate design, and shall become effective at the time the new rate classes go into effect. The new realigned conservation cost recovery factors shall be calculated using Schedule C-1 as filed in Docket No. 030004-GU for the 2004 projected period. City Gas shall file realigned conservation cost recovery factors using the approved revenue requirement in this case based on the new rate classes. See Commission Order No. PSC-00-2536-TRF-EG, issued December 29, 2000, in Docket No. 001736-EG, In re: Petition for approval of realigned conservation cost recovery factors by Florida Division of Chesapeake Utilities Corporation.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that City Gas Company of Florida's application for increased rates is hereby approved as set forth in the body of this Order. It is further

ORDERED that all findings set forth herein are approved. It is further

ORDERED that all matters contained in the attachments attached hereto are incorporated herein by reference. It is further

ORDERED that City Gas Company of Florida is authorized to collect increased revenues of $6,699,655. It is further

ORDERED that no refund of the interim increase approved by Order No. PSC-03-1217-PCO-GU, issued October 27, 2003, shall be required. It is further

ORDERED that City Gas Company of Florida shall file revised tariffs reflecting the increased rates and charges, the change in rate structure, and all other provisions approved in this Order and all other documents described herein. It is further

ORDERED that the rate increase shall be effective on billings rendered for all meter readings taken on or after February 19, 2004. It is further

ORDERED that City Gas Company of Florida shall complete an inactive service line study to determine how many of the 955 service lines should be cut/capped and physically abandoned. The study and retirements shall be completed and provided to the Bureau of Safety no later than 24 months from the date of this Order. It is further

ORDERED that City Gas Company of Florida shall file, within 90 days after the date of the final order in this docket, a full description of all entries or adjustments that will be either recorded or used in preparing its annual report, rate of return reports, and books and records which will be required. It is further

ORDERED that City Gas Company of Florida shall file realigned conservation cost recovery factors using the approved revenue requirement in this case based on the new rate classes and such conservation cost recovery factors shall become effective at the time the new rate classes go into effect. The new realigned conservation cost recovery factors shall be calculated using Schedule C-1 as filed in Docket No. 030004-GU for the 2004 projected period. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that if no timely protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of issuance of this Proposed Agency Action Order, this docket shall be closed upon the issuance of a Consummating Order.

By ORDER of the Florida Public Service Commission this 9th day of February, 2004.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records and Hearing
Services

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on March 1, 2004.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

ATTACHMENT 1

PTY 9/30/04 - FINAL RATES

COMPARATIVE AVERAGE RATE BASES

	TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
UTILITY PLANT					
PLANT IN SERVICE	$198,469,190				
To retire inactive service lines				($144,925)	
Total Plant	$198,469,190	$0	$198,469,190	($144,925)	$198,324,265
COMMON PLANT ALLOCATED		$5,723,015			
To remove cancelled NUI projects				($1,766,884)	
To remove plant unrelated to City Gas				(570,346)	
To correct for change in non-utility allocation				(34,748)	
Total Common Allocated	$0	$5,723,015	$5,723,015	($2,371,978)	$3,351,037
ACQUISITION ADJUSTMENT	$30,832,927	($29,370,230)			
Total Acquisition Adjustment	$30,832,927	($29,370,230)	$1,462,697	$0	$1,462,697
PLANT HELD FOR FUTURE USE	0				
Total Plant Held For Future Use	$0	$0	$0	$0	$0
CONSTRUCTION WORK IN PROG.	$6,452,439				
Total Construction Work In Progress	$6,452,439	$0	$6,452,439	$0	$6,452,439
TOTAL PLANT	$235,754,556	($23,647,215)	$212,107,341	($2,516,903)	$209,590,438
DEDUCTIONS					
ACCUM. DEPR.- PLANT IN SERVICE	$84,927,235				
To retire inactive service lines				($144,925)	
To correct for depreciation removed twice				115,860	
To adjust for revision in depr. rates (1/2 Y)				(121,725)	
Total Accum. Depr.- Plant In Service	$84,927,235	$0	$84,927,235	($150,790)	$84,776,445
ACCUM DEPR. - COMMON PLANT		$2,667,538			
To remove cancelled NUI projects				($119,520)	
To remove plant unrelated to City Gas				(65,149)	
To correct for change in non-utility allocation				(14,376)	
Total Accum. Depr. - Common Plant	$0	$2,667,538	$2,667,538	($199,045)	$2,468,493
ACCUM. AMORT. - ACQUIS'N ADJ.	$15,387,056	($15,160,584)			
Total Accum. Depr. - Acquisition Adj.	$15,387,056	($15,160,584)	$226,472	$0	$226,472
CUSTOMER ADV. FOR CONSTR.	$0	$0	$0	$0	$0
TOTAL DEDUCTIONS	$100,314,291	($12,493,046)	$87,821,245	($349,835)	$87,471,410
NET UTILITY PLANT	$135,440,265	($11,154,169)	$124,286,096	($2,167,068)	$122,119,028
WORKING CAPITAL ALLOWANCE	($50,638,511)	$49,774,224	($864,287)	($1,357,294)	($2,221,581)
TOTAL RATE BASE	$84,801,754	$38,620,055	$123,421,809	($3,524,362)	$119,897,447

ATTACHMENT 1A

PTY 9/30/04 - FINAL RATES

COMPARATIVE WORKING CAPITAL COMPONENTS

	TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
WORKING CAPITAL					
ASSETS					
Nonutility Property	$183,942	($183,942)	$0	$0	$0
Accum. Depr. - Nonutility Property	(29,482)	29,482	0		0
Other Special Funds	20,853	(20,853)	0		0
Cash	0	0	0		0
Working Funds & Cash Invest.	2,250		2,250		2,250
Cust. Accounts Rec. - Gas	9,487,041		9,487,041		9,487,041
Other Receivables	84,369	(8,205)	76,164		76,164
Accum. Prov. Uncollect. Accts.	(342,922)		(342,922)		(342,922)
Materials & Supplies	397,806	(41,372)	356,434		356,434
Merchandise			0		0
Prepayments	30,010		30,010		30,010
Accrued Utility Revenue	798,191		798,191		798,191
Adj. for Gain on Sale of Medley Prop.			0		0
Other Regulatory Assets	3,339,127		3,339,127		3,339,127
Deferred Conv. Cost & Piping Allowan	844,671		844,671		
To correct deferred piping for revision				61,207	905,878
Misc. Deferred Debits	448,909	(342,787)	106,122		106,122
Deferred FIT	277,744	(277,744)	0		0
Unrecovered Gas Cost/ECCR/CRA	(1,351,196)	(981,489)	(2,332,685)		(2,332,685)
To adjust Prepaid Odorant Costs				(7,774)	(7,774)
LIABILITIES					
Notes Payable	$32,286,689	($32,286,689)	$0	$0	$0
Accounts Payable	6,642,837		6,642,837		6,642,837
Customer Deposits	5,833,009	(5,833,009)	0		0
Accrued Taxes - General	146,963		146,963		
To correct RAF & property tax accrual				242,900	389,863
Accrued Interest	1,336,328	(198,324)	1,138,004		
To correct interest payable				100,639	1,238,643
Tax Collections Payable	(486,363)		(486,363)		
To correct FICA, FIT, & PRT payable				1,067,188	580,825
Misc. Current Liabilities	501,539		501,539		501,539
Capital Leases - Current	931,932		931,932		931,932
Other Regulatory Liabilities	4,396,727	(271,591)	4,125,136		4,125,136
Accum. Deferred Inc. Taxes	12,475,160	(12,475,160)	0		0
Deferred Investment Tax Credit	536,361	(536,361)	0		0
Deferred IT - Other			0		0
Capital Lease			0		0
Operating Reserves	208,260		208,260		208,260
Other Deferred Credits	20,382		20,382		20,382
TOTALS	($50,638,511)	$49,774,224	($864,287)	($1,357,294)	($2,221,581)

ATTACHMENT 2

PTY 9/30/04 - FINAL RATES

CAPITAL STRUCTURE

				COMPANY ADJUSTMENTS		
	PER BOOKS	CONFORM TO INVESTOR SOURCES	ADJUSTED BOOKS	SPECIFIC		ADJUSTED PER BOOKS
Common Equity	$28,409,942	$28,413,084	$56,823,026		($3,478,218)	$53,344,808
Long Term Debt	56,391,821	2,609,050	59,000,871		(3,611,527)	55,389,344
Short Term Debt	32,286,689	(31,022,134)	1,264,555		(77,405)	1,187,150
Customer Deposits	5,833,009		5,833,009			5,833,009
Def. Taxes-Zero Cost	12,469,007		12,469,007	(5,337,860)		7,131,147
Tax Credit-Zero Cost	536,361		536,361			536,361
	$135,926,829	$0	$135,926,829	($5,337,860)	($7,167,150)	$123,421,819

		COMMISSION RATE BASE ADJUSTMENTS							
	ADJUSTED PER BOOKS	CONFORM TO INVESTOR SOURCES	ADJ'D FOR INVESTOR SOURCES	SPECIFIC	PRO RATA	COMMISSION ADJUSTED	RATIO	COST RATE	WEIGHTED COST
Common Equity	$53,344,808	($5,690,000)	$47,654,808		($3,571,568)	$44,083,240	36.77%	11.25%	4.14%
Long Term Debt	55,389,344	(3,125,000)	52,264,344		(3,917,037)	48,347,307	40.32%	6.43%	2.59%
Short Term Debt	1,187,150	8,815,000	10,002,150		(749,628)	9,252,522	7.72%	3.90%	0.30%
Customer Deposits	5,833,009		5,833,009			5,833,009	4.86%	6.70%	0.33%
Def. Taxes-Zero Cost	7,131,147		7,131,147	4,713,871		11,845,018	9.88%		0.00%
Tax Credit-Zero Cost	536,361		536,361			536,361	0.45%		0.00%
	$123,421,819	$0	$123,421,819	$4,713,871	($8,238,233)	$119,897,457	100.0%		**7.36%**

PTY 9/30/04 - FINAL RATES

COMPARATIVE NOIs

	TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
OPERATING REVENUES	$100,402,838				
REVENUES DUE TO GROWTH	120,628				
Cost of Gas		($31,127,076)			
ECP Revenues (Conservation)		(3,138,195)			
Franchise/Gross Rec. Rev.		(3,134,516)			
Off-System Sales		(25,250,091)			
To add back duplicative RAFs removed				$154,861	
To correct rev. for errors & reduced growth				(86,663)	
To impute revenue for Clewiston				280,288	
TOTAL REVENUES	$100,523,466	($62,649,878)	$37,873,588	$348,486	$38,222,074
OPERATING EXPENSES:					
COST OF GAS					
System Supply	$31,127,076	($31,127,076)			
Off-System Sales	24,295,230	(24,295,230)			
TOTAL COST OF GAS	$55,422,306	($55,422,306)	$0	$0	$0
OPERATION & MAINTENANCE EXP.	$24,120,144				
Nonutility Expense		($35,215)			
Economic Development Activities		(878)			
AGA Dues		(2,847)			
Employee Activities		(13,053)			
Net Trend Sch. Adjs. - See Attach. 5A for refs.				($1,101,855)	
To reduce O&M due to change in factors				(59,750)	
TOTAL O & M EXPENSE	$24,120,144	($51,993)	$24,068,151	($1,161,605)	$22,906,546
CONSERVATION COSTS	$3,122,582	($3,122,582)			
Conservation Costs					
TOTAL CONSERVATION COSTS	$3,122,582	($3,122,582)	$0	$0	$0

PTY 9/30/04 - FINAL RATES

COMPARATIVE NOIs

	TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
DEPRECIATION AND AMORT.	$7,395,579				
Common Plant Depr.		$1,131,596			
NUI HQ Common Plant		(131,858)			
To remove cancelled NUI projects				($302,961)	
To remove plant unrelated to City Gas				(15,930)	
To retire inactive service lines				(10,290)	
To correct for change in non-utility allocation				(761)	
To add back depreciation removed twice				115,860	
To adjust for revision in depreciation rates				(243,449)	
TOTAL DEPRECIATION & AMORT.	$7,395,579	$999,738	$8,395,317	($457,531)	$7,937,786
TAXES OTHER THAN INCOME	$5,543,562				
Gross receipts, franchise fees		($3,134,516)			
Regulatory Assessment Fees		(170,474)			
Common Plant Property Taxes		(21,646)			
To adj. RAFS, and Payroll & property taxes				$81,002	
TOTAL TAXES OTHER THAN INC.	$5,543,562	($3,326,636)	$2,216,926	$81,002	$2,297,928
INCOME TAX EXPENSE					
Income Taxes - Federal	($1,807,323)				
Income Taxes - State	(309,376)				
Deferred Income Taxes - Federal	1,498,418				
Deferred Income Taxes - State	296,273				
FIT & SIT Taxes on Company Adjs.		($649,536)			
Interest Synchronization - Company Adj.		567,781			
Tax Effect of Other Adjustments				$709,935	
Interest Reconciliation Adjustment				52,108	
TOTAL INCOME TAXES	($322,008)	($81,755)	($403,763)	$762,043	$358,280
TOTAL OPERATING EXPENSES	$95,282,165	($61,005,534)	$34,276,631	($776,091)	$33,500,540
NET OPERATING INCOME	$5,241,301	($1,644,344)	$3,596,957	$1,124,577	$4,721,534

ATTACHMENT 4

PTY 9/30/04 - FINAL RATES

NET OPERATING INCOME MULTIPLIER

DESCRIPTION	COMPANY PER FILING	COMMISSION
REVENUE REQUIREMENT	100.0000%	100.0000%
REGULATORY ASSESSMENT RATE	0.5000%	0.5000%
BAD DEBT RATE	1.6716%	1.3103%
NET BEFORE INCOME TAXES	97.8284%	98.1897%
STATE INCOME TAX RATE	5.5000%	5.5000%
STATE INCOME TAX	5.3806%	5.4004%
NET BEFORE FEDERAL INCOME TAXES	92.4478%	92.7893%
FEDERAL INCOME TAX RATE	34.0000%	34.0000%
FEDERAL INCOME TAX	31.4323%	31.5484%
REVENUE EXPANSION FACTOR	61.0156%	61.2409%
NET OPERATING INCOME MULTIPLIER	1.6389	1.6329

ATTACHMENT 5

PTY 9/30/04 - FINAL RATES

COMPARATIVE REVENUE DEFICIENCY CALCULATIONS

		COMPANY ADJUSTED	COMMISSION
RATE BASE (AVERAGE)		$123,421,809	$119,897,447
RATE OF RETURN	X	8.10%	7.36%
REQUIRED NOI		$9,997,167	$8,824,452
Operating Revenues		37,873,588	38,222,074
Operating Expenses:			
Operation & Maintenance		24,068,151	22,906,546
Depreciation & Amortization		8,395,317	7,937,786
Amortization of Environ. Costs		0	0
Taxes Other than Income Taxes		2,216,926	2,297,928
Income Taxes		(403,763)	358,280
Total Operating Expenses		34,276,631	33,500,540
ACHIEVED NOI		3,596,957	4,721,534
NET NOI DEFICIENCY		6,400,210	4,102,918
REVENUE TAX FACTOR		1.6389	1.6329
REVENUE DEFICIENCY		$10,489,303	$6,699,655

PTY 9/30/04 - FINAL RATES

OPERATIONS AND MAINTENANCE EXPENSE TREND SCHEDULE

	TREND RATES:	BASE YEAR + 1 9/30/2003	PROJECTED TEST YEAR 09/30/2004
# 1	Payroll Rate Increase	103.00%	104.00%
# 2	General Inflation Rate	102.30%	102.00%
# 3	Customer Growth Rate	99.85%	99.44%
# 4	Payroll and General Inflation	105.37%	106.08%
#5	Payroll and Customer Growth	102.85%	103.42%
#6	General Inflation and Customer Growth	102.15%	101.43%

ACCOUNT	BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
DISTRIBUTION EXPENSE				
870 Operation Supervision & Engineering				
Payroll - not trended	682,902	703,389	792,293	
Other - trended	243,969	249,206	252,767	6
Total	926,871	952,595	1,045,060	
874 Main & Service Expense				
Payroll - trended	92,150	94,915	98,711	1
Payroll - not trended	1,340,527	1,380,743	1,623,301	
Other - trended	126,446	129,160	131,006	6
Other - not trended	139,214	142,667	132,516	
Comm. Adjustment - Electric Bills	(19,043)	(19,452)	(19,730)	6
Total	1,679,294	1,728,033	1,965,804	
875 Measuring & Regulating Station General				
Payroll - trended	17,714	18,245	18,975	1
Other - trended	30	31	31	6
Total	17,744	18,276	19,006	
877 Measure & Regulating Station City Gate				
Payroll - not trended		0	606	
Total	0	0	606	
878 Meter & House Regulator Expense				
Payroll - not trended	328,308	338,157	415,112	
Other - trended	98,464	100,578	102,015	6
Other - not trended	336,027	344,360	0	
Total	762,799	783,095	517,127	
879 Customer Service Expense				
Payroll - not trended	90,758	93,481	66,628	
Other - not trended	27,029	27,699	30,359	
Total	117,787	121,180	96,987	

PTY 9/30/04 - FINAL RATES

	BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
880 Other Expense Maps & Records				
Payroll - trended	31,463	32,407	33,703	1
Payroll - not trended	524,245	539,972	592,925	
Other - trended	280,436	286,456	290,549	6
Other - not trended	(132,486)	(135,772)	121,886	
Other - not trended	305,594	313,173	12,000	
Comm. adjustment - Non-Utility Expenses	(45,286)	(46,258)	(46,919)	6
Total	963,966	989,977	1,004,144	
Total Distribution Expense	$4,468,461	$4,593,156	$4,648,733	
MAINTENANCE EXPENSE				
885 Maintenance Supervision & Engineering				
Payroll - trended	55,367	57,028	59,309	1
Other - trended	33,470	34,188	34,677	6
Total	88,837	91,216	93,986	
886 Maintenance of Structures & Improvements				
Other - trended	19,260	19,703	20,097	2
Total	19,260	19,703	20,097	
887 Maintenance of Mains				
Payroll - trended	88,720	91,382	95,037	1
Other - trended	477,484	487,733	494,702	6
Total	566,204	579,115	589,739	
889 Maintenance of Meas. & Reg. Station General				
Payroll - trended	3,739	3,851	4,005	1
Total	3,739	3,851	4,005	
890 Maintenance of Meas. & Reg. Station Industrial				
Payroll - trended	56,997	58,707	61,055	1
Other - trended	23,534	24,039	24,383	6
Total	80,531	82,746	85,438	
891 Maintenance of Meas. & Reg. Station City Gate				
Payroll - trended	36,987	38,097	39,620	1
Other - trended	7,310	7,467	7,574	6
Comm. adjustment - To increase odorant costs	15,007	15,329	15,548	6
Total	59,304	60,893	62,742	
892 Maintenance of Services				
Payroll - trended	10,238	10,545	10,967	1
Payroll - not trended	35,704	36,775	54,283	
Other - trended	86,023	87,870	89,125	6
Total	131,965	135,190	154,375	

PTY 9/30/04 - FINAL RATES

	BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
893 Maintenance of Meters & House Regulators				
Payroll - trended	132,127	136,091	141,534	1
Other - trended	44,624	45,582	46,233	6
Total	176,751	181,673	187,768	
894 Maintenance of Other Equipment				
Other - trended	8,449	8,630	8,754	6
Total	8,449	8,630	8,754	
Total Maintenance Expense	$1,135,040	$1,163,017	$1,206,904	
CUSTOMER ACCOUNT EXPENSE				
901 Supervision				
Other - trended	14,395	14,704	14,914	6
Total	14,395	14,704	14,914	
902 Meter Reading Expense				
Payroll - trended	408,690	420,951	437,789	1
Other - trended	68,626	70,099	71,101	6
Other - not trended	18,226	18,678	38,531	
Total	495,542	509,728	547,420	
903 Customer Records & Collections				
Payroll - not trended	999,704	1,029,695	(1,073,947)	
Payroll - not trended	45,765	47,138	1,207,193	
Other - not trended	1,215,656	1,245,804	1,461,359	
Comm. adjustment - To adjust UBS costs			(117,831)	
Total	2,261,125	2,322,637	1,476,774	
904 Uncollectible Accounts				
Other - trended	1,200,000	1,225,759	1,243,272	6
Comm. adjustment - Bad Debt Expense		0	(256,071)	
Total	1,200,000	1,225,759	987,201	
Total Customer Account Expense	$3,971,062	$4,072,827	$3,026,310	
SALES EXPENSE				
909 ECP				
Payroll - not trended	423,410	436,112	590,900	
Other - not trended	1,120,964	1,148,764	2,531,682	
Total	1,544,374	1,584,876	3,122,582	

PTY 9/30/04 - FINAL RATES

		BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
911	Supervision				
	Payroll - not trended	164,596	169,534	311,922	
	Other - not trended	3,376	3,460	4,894	
	Total	167,972	172,994	316,816	
912	Selling & Demonstrating Expense				
	Payroll - trended	8,037	8,278	8,609	1
	Payroll - not trended	282,584	291,062	450,533	
	Other - trended	65,659	67,068	68,027	6
	Other - not trended	82,527	84,574	347,400	
	Other - not trended - Amort. of def. piping	376,164	385,493	328,740	
	Comm. adjustment - To remove Demon. & Selling		0	(513,644)	
	Total	814,971	836,476	689,665	
913	Advertising Expense				
	Other - trended	7,037	7,188	7,291	6
	Other - not trended		0	210,000	
	Comm. adjustment - To remove advertising costs		0	(210,000)	
	Total	7,037	7,188	7,291	
916	Miscellaneous Sales Expense				
	Other - trended	9,331	9,531	9,667	6
	Other - not trended	31,665	32,450	66,000	
	Comm. adjustment - To adj. Misc. Sales Exp.			(33,191)	
	Total	40,996	41,981	42,476	
Total Sales Expense		$2,575,350	$2,643,515	$4,178,830	

ADMINISTRATIVE & GENERAL EXPENSES

		BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
920	Administrative & General Salaries				
	Payroll - trended	246,886	254,293	264,464	1
	Total	246,886	254,293	264,464	
921	Office Supplies & Expenses				
	Other - trended	1,918,906	1,963,041	2,002,302	2
	Other - not trended	835	835	0	
	Comm. adjustment - Ankron Plaza Rent	(6,225)	(6,368)	(6,496)	2
	Comm. adjustment - Copy machine rent	(548)	(561)	(572)	2
	Comm. adjustment - Minolta costs	(622)	(636)	(649)	2
	Comm. adjustment - Donation alloc'd in	(34,149)	(34,934)	(35,633)	2
	Comm. adjustment - To remove written off Exp.	(314,691)	(321,929)	(328,367)	2
	Comm. adjustment - To adjust AGA Dues		(12,920)	(13,178)	2
	Total	1,563,506	1,586,528	1,617,407	

PTY 9/30/04 - FINAL RATES

	BASE YEAR 2002	BASE YEAR + 1 2003	PROJECTED TEST YEAR 2004	TREND BASIS APPLIED
923 Outside Services Employed				
Other - trended	2,720,917	2,783,498	2,839,168	2
Other - not trended	864,442	885,880	2,373,697	
Other - not trended	1,175,768	1,204,927	1,757,142	
Comm. adjustment - To incr allocated exec exp.			866,569	
Total	4,761,127	4,874,305	7,836,576	
925 Injuries & Damages				
Other - not trended	847,806	868,832	1,244,650	
Comm. adjustment - To adj. for NUI alloc change		0	(336,952)	
Total	847,806	868,832	907,698	
926 Employee Pensions/Benefits				
Other - not trended	748,502	767,065	1,398,339	
Other - not trended - Pensions & Stock Grants	53,129	54,447	705,013	
Other - trended	65,983	67,501	68,851	2
Comm. adjustment - To remove duplicate exp.		0	(50,960)	2
Total	867,614	889,013	2,121,243	
928 Regulatory Commission Expense				
Other - not trended - Rate Case Expense	85,404	85,404	165,090	
Comm. adjustment - To adj to actual		0	(5,671)	
Total	85,404	85,404	159,419	
930.2 Miscellaneous General Expenses				
Other - trended	2,287	2,340	2,386	2
Total	2,287	2,340	2,386	
931 Rents				
Other - trended	114,305	116,934	119,273	2
Comm. adjustment - 74th St. rent	(7,771)	(7,950)	(8,109)	2
Total	106,534	108,984	111,164	
Total Administrative & General Expenses	$8,481,164	$8,669,698	$13,020,357	
TOTAL OPERATION & MAINTENANCE EXPENSES	$20,631,077	$21,142,213	$26,081,134	
		Less: Company Adjs.	(3,174,575)	
		Comm. adjusted O&M	$22,906,559	

	2004 Per Company	Comm. Adjustm'ts	2004 Per Comm.
Total Payroll - Trended	$1,273,780	($0)	$1,273,780
Total Payroll - Not Trended	5,031,749	0	5,031,749
Total Other - Trended	8,007,912		
Less: Comm. Adjustment for Trend Factors		(59,750)	7,948,162
Total Other - Not Trended	12,929,298	0	12,929,298
Total Company Adjustments	(3,174,575)	0	(3,174,575)
Less: Comm. Adjustments to Accounts		(1,101,855)	(1,101,855)
Total Net O&M	$24,068,164	($1,161,605)	$22,906,559

COST OF SERVICE
CLASSIFICATION OF RATE BASE
(Page 1 of 2: PLANT)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
302 FRANCHISES AND CONSENTS	141,459		141,459		
303 MISC INTANGIBLE PLANT	14,728		**14,728**		
LOCAL STORAGE PLANT	**156,187**		156,187		100% capacity
INTANGIBLE PLANT:	**0**				100% capacity
PRODUCTION PLANT	**0**				100% capacity
DISTRIBUTION PLANT:	**0**				100% capacity
374 Land and Land Rights	55,027		55,027		100% capacity
375 Structures and Improvements	434,618		434,618		100% capacity
376 Mains	123,183,185		123,183,185		100% capacity
377 Comp.Sta.Eq.	0				100% capacity
378 Meas.& Reg.Sta.Eq.-Gen	0				100% capacity
379 Meas.& Reg.Sta.Eq.-CG	5,574,353		5,574,353		100% capacity
380 Services	40,087,555	40,087,555			100% customer
381- 382 Meters	12,133,938	12,133,938			100% customer
383- 384 House Regulators	3,248,831	3,248,831			100% customer
385 Industrial Meas.& Reg.Eq.	2,752,375		2,752,375		100% capacity
386 Property on Customer Premises	0				ac 374-385
387 Other Equipment	155,827	46,108	109,719		ac 374-386
Total Distribution Plant	**187,781,896**	**55,516,432**	**132,265,464**	**0**	
GENERAL PLANT:	**13,893,404**	**6,946,702**	**6,946,702**	**0**	50% customer, 50% capacity
TOTAL DIST/INTANGIBLE/GENERAL	**201,675,300**	**62,463,134**	**139,212,166**	**0**	
PLANT ACQUISITIONS:	**1,462,697**	**0**	**1,462,697**	**0**	100% capacity
GAS PLANT FOR FUTURE USE:	**0**	**0**	**0**	**0**	100% capacity
CWIP:	**6,452,439**	**1,907,619**	**4,544,820**	**0**	dist.plant
TOTAL PLANT	**209,590,436**	**64,370,753**	**145,219,683**	**0**	

COST OF SERVICE
CLASSIFICATION OF RATE BASE
(PAGE 2 OF 2: ACCUMULATED DEPRECIATION)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
LOCAL STORAGE PLANT:	**98,885**	0	98,885	0	related plant
INTANGIBLE PLANT	**0**	0		0	
DISTRIBUTION PLANT:					
374 Land and Land Rights	0	0		0	"
375 Structures and Improvements	169,672	0	169,672	0	"
376 Mains	49,205,588	0	49,205,588	0	"
377 Comp.Sta.Eq.	0	0	0	0	"
378 Meas.& Reg.Sta.Eq.-Gen	0	0		0	"
379 Meas.& Reg.Sta.Eq.-CG	1,645,954	0	1,645,954	0	"
380 Services	21,590,079	21,590,079	0	0	"
381- 382 Meters	4,489,838	4,489,838	0	0	
383- 384 House Regulators	1,356,031	1,356,031	0	0	
385 Industrial Meas.& Reg.Eq.	964,901	0	964,901	0	"
386 Property on Customer Premises	0	0		0	"
387 Other Equipment	169,737	50,223	119,514	0	"
Total Distribution Plant	**79,591,800**	**27,486,171**	**52,105,629**	**0**	
GENERAL PLANT:	**7,554,254**	**3,777,127**	**3,777,127**	**0**	general plant
AMORT. ACQ. ADJUSTMENT	**226,472**	**0**	**226,472**	**0**	plant acquisitions
RETIREMENT WORK IN PROGRESS:		**0**	**0**	**0**	distribution plant
CUST. ADVANCES FOR CONSTRUCTION					50% customer 50% capacity
TOTAL ACCUMULATED DEPRECIATION	**87,471,411**	**31,263,298**	**56,208,113**	**0**	
NET PLANT (Plant less Accum.Dep.)	**122,119,025**	**33,107,455**	**89,011,570**	**0**	
less: CUSTOMER ADVANCES	**0**	**0**	**0**		50% cust 50% cap
plus: WORKING CAPITAL	**(2,221,581)**	**(1,207,684)**	**(793,218)**	**(220,679)**	oper. and maint. exp.
equals: TOTAL RATE BASE	**119,897,444**	**31,899,771**	**88,218,352**	**(220,679)**	

COST OF SERVICE
CLASSIFICATION OF EXPENSES
(PAGE 1 OF 2)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
OPERATIONS AND MAINTENANCE EXPENSES					
LOCAL STORAGE PLANT:	0	0	0	0	ac 301-320
PRODUCTION PLANT	0	0	0	0	100% capacity
DISTRIBUTION:					
870 Operation Supervision & Eng.	1,045,060	440,924	604,136	0	ac 871-879
871 Dist.Load Dispatch			0		100% capacity
872 Compr.Sta.Lab. & Ex.			0	0	ac 377
873 Compr.Sta.Fuel & Power				0	100% commodity
874 Mains and Services	1,965,805	482,660	1,483,145	0	ac376+ac380
875 Meas.& Reg. Sta.Eq.-Gen	19,006	0	19,006	0	ac 378
876 Meas.& Reg. Sta.Eq.-Ind.		0	0	0	ac 385
877 Meas.& Reg. Sta.Eq.-CG	606	0	606	0	ac 379
878 Meter and House Reg.	517,127	517,127	0	0	ac381+ac383
879 Customer Instal.	96,987	96,987	0	0	ac 386
880 Other Expenses	1,004,140	395,643	608,497	0	ac 387
881 Rents	0		0		100% capacity
885 Maintenance Supervision	93,986	29,113	64,873	0	ac886-894
886 Maint. of Struct. and Improv.	20,097	0	20,097	0	ac375
887 Maintenance of Mains	589,737	0	589,737	0	ac376
888 Maint. of Comp.Sta.Eq.		0	0	0	ac 377
889 Maint. of Meas.& Reg. Sta.Eq.-Gen	4,005	0	4,005	0	ac 378
890 Maint. of Meas.& Reg. Sta.Eq.-Ind.	85,436	0	85,436	0	ac 385
891 Maint. of Meas.& Reg.Sta.Eq.-CG	62,742	0	62,742	0	ac 379
892 Maintenance of Services	154,375	154,375	0	0	ac 380
893 Maint. of Meters and House Reg.	187,769	187,769	0	0	ac381-383
894 Maint. of Other Equipment	8,753	2,590	6,163	0	ac387
Total Distribution Expenses	5,855,631	2,307,188	3,548,443	0	
CUSTOMER ACCOUNTS:					
901 Supervision	14,914	14,914			
902 Meter-Reading Expense	547,420	547,420			
903 Records and Collection Exp.	1,476,774	1,476,774			
904 Uncollectible Accounts	987,201			987,201	100% commodity
905 Misc. Expenses	0	0			
Total Customer Accounts	3,026,309	2,039,108	0	987,201	
(907-910) CUSTOMER SERV.& INFO. EXP.	0	0			
(911-916) SALES EXPENSE	1,056,248	1,056,248			100% CUSTOMER
(932) MAINT. OF GEN. PLANT		0	0	0	
(920-931) ADMINISTRATION AND GENERAL	12,968,357	7,049,788	4,630,369	1,288,200	O&M excl. A&G
TOTAL O&M EXPENSE	22,906,545	12,452,332	8,178,812	2,275,401	

COST OF SERVICE
CLASSIFICATION OF EXPENSES
(Page 2 of 2)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE	CLASSIFIER
DEPRECIATION AND AMORTIZATION EXPENSE:						
Depreciation Expense	$7,812,458	$2,118,021	$5,694,437	$0		Net plant
Amort. of Environmental			$0			100% capacity
Amort. of Property Loss			$0			100% capacity
Amort. of lease improvements/other			$0			Intan/dist/gen plant
Amort. of Acquisitiion Adj.	$46,740	$14,475	$32,265			Intan/dist/gen plant
Amort. of Conversion Costs	$78,588			$78,588		100% commodity
Total Deprec. and Amort. Expense	**7,937,786**	**2,132,496**	**5,726,702**	**78,588**	**0**	
TAXES OTHER THAN INCOME TAXES:						
Revenue Related	$438,165				$438,165	100% revenue
Other	$1,859,762	$504,197	$1,355,565	$0		Net plant
Total Taxes other than Income Taxes	**2,297,927**	**504,197**	**1,355,565**	**0**	**438,165**	
REV.CRDT TO COS (NEG.OF OTHR OPR.REV)	**($1,015,170)**	**($1,015,170)**				100% customer
RETURN (REQUIRED NOI)	**$8,824,452**	**$2,347,823**	**$6,492,871**	**($16,242)**		Rate base
INCOME TAXES	**$358,280**	**$95,324**	**$263,616**	**($659)**	**$0**	Return(noi)
TOTAL OVERALL COST OF SERVICE	**41,309,820**	**16,517,001**	**22,017,566**	**2,337,088**	**438,165**	

COST OF SERVICE
SUMMARY

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

SUMMARY:	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE
ATTRITION	0	0	0	0	
OPERATION AND MAINTENANCE EXPENSE	22,906,545	12,452,332	8,178,812	2,275,401	
LESS O&M DIRECT ASSIGNMENTS	(3,500,249)	(1,341,931)	(2,158,318)	0	
NET O&M	19,406,296	11,110,401	6,020,494	2,275,401	0
DEPRECIATION EXPENSE	7,812,458	2,118,021	5,694,437	0	0
AMORT. OF OTHER GAS PLANT	0	0	0	0	0
AMORT. OF PROPERTY LOSS	0	0	0	0	0
AMORT. OF LIMITED-TERM INVESTMENT	0	0	0	0	0
AMORT. OF ACQUISITION ADJUSTMENT	46,740	14,475	32,265	0	0
AMORT. OF CONVERSION COSTS	78,588	0	0	78,588	0
TAXES OTHER THAN INCOME TAXES	2,297,927	504,197	1,355,565	0	438,165
RETURN	8,824,452	2,347,823	6,492,871	(16,242)	0
INCOME TAXES	358,280	95,324	263,616	0	0
REV.CRD. TO COS	(1,015,170)	(1,015,170)	0	0	0
TOTAL COST OF SERVICE	**41,309,820**	**16,517,001**	**22,017,566**	**2,337,088**	**438,165**
RATE BASE	**119,897,444**	**31,899,771**	**88,218,352**	**(220,679)**	**0**
less: Rate Base direct assignments	**(103,799,447)**	**(28,034,376)**	**(75,765,071)**	**0**	**0**
NET RATE BASE	**16,097,997**	**3,865,395**	**12,453,281**	**(220,679)**	**0**

KNOWN DIRECT & SPECICAL ASSIGNMENTS:

RATE BASE ITEMS (PLANT-ACC.DEP):	TOTAL	CUSTOMER	CAPACITY	COMMODITY
381-382 METERS	7,644,100	7,644,100	0	0
383-384 HOUSE REGULATORS	1,892,800	1,892,800	0	0
385 INDUSTRIAL MEAS.& REG.EQ.	1,787,474	0	1,787,474	0
376 MAINS	73,977,597	0	73,977,597	0
380 SERVICES	18,497,476	18,497,476	0	0
378 MEAS.& REG.STA.EQ.-GEN.	0	0	0	0
Total Rate Base Direct Assignments	**103,799,447**	**28,034,376**	**75,765,071**	**0**

O&M ITEMS	TOTAL	CUSTOMER	CAPACITY	COMMODITY
892 Maint. of Services O & M ITEMS	154,375	154,375	0	0
876 MEAS.& REG.STA.EQ.IND.	0	0	0	0
878 METER & HOUSE REG.	517,127	517,127	0	0
890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	85,436	0	85,436	0
893 MAINT.OF METERS AND HOUSE REG.	187,769	187,769	0	0
874 MAINS AND SERVICES	1,965,805	482,660	1,483,145	0
887 MAINT. OF MAINS	589,737	0	589,737	0
Total O&M Direct Assignments	**3,500,249**	**1,341,931**	**2,158,318**	**0**

COST OF SERVICE
DEVELOPMENT OF ALLOCATION FACTORS

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
CUSTOMER COSTS																
No. of Customers	101,459	18,549	43,231	33,768	1,229	2,186	1,742	331	79	50	30	12	248	3	1	
Weighting	N/A	1.00	1.30	1.69	2.25	3.61	4.57	6.78	14.36	17.68	23.06	63.11	1.00	4.57	0.00	n/a
Weighted No. of Customers	156,414	18,549	56,200	57,068	2,766	7,890	7,959	2,246	1,140	884	692	757	248	14	0	0
Allocation Factors	100%	11.8591%	35.9304%	36.4853%	1.7681%	5.0444%	5.0887%	1.4359%	0.7291%	0.5652%	0.4423%	0.4842%	0.1586%	0.0088%	0.0000%	0.0000%
house reg allocator - uses only res customers	95,961	18,166	43,431	33,387	873	104										
	100%	18.93020%	45.25906%	34.79271%	0.90940%	0.10864%										
No. of Customers: Total Annual Bills	1,217,492	222,591	518,769	405,217	14,750	26,228	20,900	3,975	953	600	360	126	2,976	36	12	0
CAPACITY COSTS																
Peak & Avg. Month Sales Vol. (therms)	17,090,237	207,066	1,441,302	2,383,814	227,727	1,296,143	3,712,361	2,062,845	1,141,142	1,498,235	2,065,940	1,041,464	11,080	1,118	0	0
Allocation Factors	100%	1.2116%	8.4335%	13.9484%	1.3325%	7.5841%	21.7221%	12.0703%	6.6772%	8.7666%	12.0884%	6.0939%	0.0648%	0.0065%	0.0000%	0.0000%
Industrial Meas. & Reg. Sta. Eq.	11,534,185	0	0	0	0	0	3,712,361	2,062,845	1,141,142	1,498,235	2,065,940	1,041,464	11,080	1,118	0	0
							32.19%	17.88%	9.89%	12.99%	17.91%	9.03%	0.10%	0.01%	0.00%	0.00%
COMMODITY COSTS																
Annual Sales Vol.(therms)	111,219,921	1,048,530	7,249,620	10,686,950	1,120,500	7,276,670	20,541,864	11,533,090	6,313,260	8,801,385	12,931,652	16,871,740	66,480	12,000	6,766,180	
Allocation Factors	100%	0.9428%	6.5183%	9.6088%	1.0075%	6.5426%	18.4696%	10.3696%	5.6764%	7.9135%	11.6271%	15.1697%	0.0598%	0.0108%	6.0836%	
REVENUE-RELATED COSTS																
Tax on Cust., Cap. & Commod.	153,677	8,459	31,259	34,685	2,387	9,539	21,961	12,331	6,614	6,645	8,963	8,308	158	12	1,637	718
Allocation Factors	100.0000%	5.5045%	20.3407%	22.5697%	1.5534%	6.2075%	14.2905%	8.0242%	4.3037%	4.3239%	5.8325%	5.4062%	0.1029%	0.0077%	1.0653%	0.4674%
Allocation Factors Excluding Direct Assign	101.2777%	6.6023%	24.3975%	27.0710%	1.8633%	7.4455%	17.1407%	9.6246%	5.1620%	0.0000%	0.0000%	0.0000%	0.1234%	0.0092%	1.2777%	0.5606%

COST OF SERVICE
ALLOCATION OF RATE BASE TO CUSTOMER CLASSES

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

RATE BASE BY CUSTOMER CLASS	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
DIRECT AND SPECIAL ASSIGNMENTS:																
Customer																
Meters	7,644,100	906,522	2,746,554	2,788,976	135,159	385,599	388,985	109,758	55,734	43,202	33,809	37,011	12,120	670	0	0
House Regulators	1,892,800	358,311	856,663	658,556	17,213	2,056	0	0	0	0	0	0	0	0	0	0
Services	18,497,476	2,140,356	6,484,788	6,584,949	319,119	910,424	918,419	259,146	131,591	102,003	79,825	87,385	28,616	1,582	449,272	0
General Plant	3,169,575	375,883	1,138,840	1,156,430	56,043	159,886	161,290	45,511	23,110	17,913	14,019	15,346	5,025	278	0	0
All Other	695,820	81,688	247,496	251,318	12,179	34,747	35,052	9,890	5,022	3,893	3,047	3,335	1,092	60		7,000
Total Customer	31,899,771	3,862,760	11,474,341	11,440,230	539,714	1,492,712	1,503,747	424,306	215,457	167,011	130,700	143,078	46,854	2,590	449,272	7,000
Capacity																
Industrial Meas. & Reg. Sta. Eq.	1,787,474	0	0	0	0	0	523,814	291,067	161,015	211,401	291,504	146,951	1,563	158	160,000	
Meas. & Reg. Sta. Eq.-Gen.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Mains	67,864,523	822,251	5,723,342	9,466,011	904,294	5,146,922	14,741,611	8,191,458	4,531,420	5,949,421	8,203,750	4,135,603	43,998	4,440	0	
Mains Large Volume	6,113,074										484,800	3,044,700			2,583,574	
General Plant	3,169,575	38,403	267,306	442,105	42,235	240,384	688,499	382,578	211,637	277,864	383,152	193,151	2,055	207	0	
All Other	9,283,706	112,482	782,940	1,294,928	123,705	704,087	2,016,618	1,120,572	619,888	813,867	1,122,254	565,741	6,019	607	0	
Total Capacity	88,218,352	973,135	6,773,587	11,203,044	1,070,234	6,091,392	17,970,542	9,985,675	5,523,961	7,252,553	10,485,460	8,086,146	53,635	5,413	2,743,574	
Commodity																
Account #	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Account #	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Account #	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
All Other	(220,679)	(2,080)	(14,384)	(21,205)	(2,223)	(14,438)	(40,758)	(22,884)	(12,527)	(17,463)	(25,659)	(33,476)	(132)	(24)	(13,425)	
Total	(220,679)	(2,080)	(14,384)	(21,205)	(2,223)	(14,438)	(40,758)	(22,884)	(12,527)	(17,463)	(25,659)	(33,476)	(132)	(24)	(13,425)	
TOTAL	119,897,444	4,833,815	18,233,544	22,622,070	1,607,725	7,569,666	19,433,531	10,387,098	5,726,891	7,402,100	10,590,501	8,195,747	100,357	7,979	3,179,421	7,000

COST OF SERVICE
ALLOCATION OF EXPENSES TO CUSTOMER CLASSES

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
Customer	14,584,828	1,707,039	5,211,937	5,251,821	254,513	726,108	732,484	206,682	104,951	81,352	63,665	29,694	22,823	1,262	0	
Capacity	13,475,721	153,106	1,093,070	1,138,863	167,396	697,800	1,834,233	1,242,541	637,105	342,455	412,954	508,368	247,829	524	138,763	
Commodity	2,353,989	23,582	163,047	240,354	25,201	163,655	461,995	259,384	141,988	197,947	290,838	379,452	1,495	270	4,781	
Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	30,414,538	1,883,727	6,468,054	6,631,037	447,110	1,587,563	3,028,713	1,708,607	884,044	621,754	767,457	917,515	272,147	2,055	143,544	0
OPERATIONS AND MAINTENANCE EXPENSE:																
DIRECT AND SPECIAL ASSIGNMENTS:																
Customer																
878 Meters and House Regulators	517,127	61,327	185,806	188,676	9,144	26,086	26,315	7,425	3,770	2,923	2,287	2,504	820	45	0	
893 Maint. of Meters & House Reg.	187,769	22,268	67,466	68,508	3,320	9,472	9,555	2,696	1,369	1,061	830	909	298	16	0	
874 Mains & Services	482,660	57,239	173,422	176,100	8,534	24,347	24,561	6,930	3,519	2,728	2,135	2,337	765	42	0	
892 Maint. of Services	154,375	18,307	55,468	56,324	2,730	7,787	7,856	2,217	1,126	872	683	747	245	14	0	
All Other	11,110,401	1,295,003	3,963,562	3,984,164	193,080	550,844	555,681	156,794	79,618	61,716	48,298	12,872	17,314	957	0	190,498
Total	12,452,332	1,454,144	4,445,723	4,473,772	216,808	618,536	623,968	176,062	89,402	69,300	54,233	19,369	19,442	1,075	0	190,498
Capacity																
876 Measuring & Reg. Sta. Eq.- I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
890 Maint. of Meas.& Reg.Sta.Eq.-I	85,436	0	0	0	0	0	0	0	0	27,786	38,315	19,315	0	21	0	0
874 Mains and Services	1,412,383	17,113	144,113	197,005	18,820	137,117	306,800	210,479	94,307	113,818	145,735	26,069	916	92	0	0
874 Mains and Services LV	70,761	0	0	0	0	0	0	0	0	0	9,720	61,042	0	0	0	0
887 Maint. of Mains	561,600	6,804	47,362	78,334	7,483	42,592	121,992	67,787	37,499	49,233	67,889	34,223	364	37	0	0
887 Maint. of Mains LV	28,137	0	0	0	0	0	0	0	0	0	3,865	24,272	0	0	0	0
All Other	5,710,504	129,189	901,594	863,524	141,092	518,091	1,405,442	964,276	505,299	151,618	69,310	56,993	3,702	374	0	
All Other LV	309,990	0	0	0	0	0	0	0	0	0	39,454	247,786	0	0	22,750	0
Total	8,178,812	153,106	1,093,070	1,138,863	167,396	697,800	1,834,233	1,242,541	637,105	342,455	374,286	469,700	4,982	524	22,750	0
Commodity																
Account #	0	0	0	0	0	0										
All Other	2,275,401	22,841	157,924	232,803	24,409	158,514	447,480	251,235	137,527	191,728	281,701	367,531	1,448	261		
Total	2,275,401	22,841	157,924	232,803	24,409	158,514	447,480	251,235	137,527	191,728	281,701	367,531	1,448	261	0	0
TOTAL O&M	22,906,545	1,630,091	5,696,717	5,845,437	408,612	1,474,850	2,905,682	1,669,839	864,035	603,483	710,220	856,600	25,872	1,860	22,750	190,498
DEPRECIATION EXPENSE:																
Customer	2,118,021	251,178	761,013	772,767	37,450	106,841	107,760	30,412	15,443	11,970	9,368	10,255	3,358	186	0	0
Capacity	5,296,909	64,178	446,714	738,834	70,581	401,724	1,150,601	639,353	353,683	464,360	640,313	322,789	3,434	347	0	0
Capacity LV	397,528	0	0	0	0	0	0	0	0	0	38,668	242,647	0	0	116,013	0
Total	7,414,930	315,356	1,207,727	1,511,601	108,031	508,565	1,258,361	669,765	369,126	476,330	688,349	575,691	6,792	532	116,013	0
AMORT. OF ENVIRONMENTAL																
Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AMORT. OF PROPERTY LOSS																
Capacity	0	0	0	0	0	0										
AMORT OF LEASEHOLD / OTHER																
Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AMORT. OF ACQUISITION ADJ.:																
Customer	14,475	1,717	5,201	5,281	256	730	737	208	106	82	64	70	23	1	0	0
Capacity	32,265	391	2,721	4,500	430	2,447	7,009	3,894	2,154	2,829	3,900	1,966	21	2	0	0
Total	46,740	2,108	7,922	9,782	686	3,177	7,745	4,102	2,260	2,910	3,964	2,036	44	3	0	0
AMORT. OF CONVERSION COSTS:																
Commodity	78,588	741	5,123	7,551	792	5,142	14,515	8,149	4,481	6,219	9,138	11,922	47	8	4,781	0

COST OF SERVICE
ALLOCATION OF EXPENSES TO CUSTOMER CLASSES

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO.: 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
TAXES OTHER THAN INCOME TAXES:																
Customer	504,197	59,793	181,160	183,958	8,915	25,434	25,657	7,240	3,676	2,850	2,230	2,441	799	44	0	0
Capacity	1,243,550	15,067	104,875	173,455	16,570	94,312	270,125	150,100	83,034	109,017	150,326	75,781	806	81	0	0
Capacity LV	112,016	0	0	0	0	0	0	0	0	0	8,883	55,791	0	0	47,341	0
Subtotal	1,747,746	74,860	286,034	357,413	25,485	119,746	295,782	157,340	86,710	111,867	161,439	134,013	1,606	126	47,341	0
Revenue	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
Total	2,185,911	98,979	375,160	456,306	32,292	146,945	358,398	192,499	105,567	130,813	186,995	157,701	2,056	159	52,009	2,048
RETURN (NOI)																
Customer	2,347,823	284,299	844,511	842,001	39,723	109,864	110,676	31,229	15,858	12,292	9,619	10,531	3,448	191	33,066	515
Capacity	6,042,948	71,623	498,536	824,544	78,769	448,326	1,322,632	734,946	406,563	533,788	736,049	371,050	3,948	398	11,776	0
Capacity LV	449,922	0	0	0	0	0	0	0	0	0	35,681	224,090	0	0	190,151	0
Commodity	(16,242)	(153)	(1,059)	(1,561)	(164)	(1,063)	(3,000)	(1,684)	(922)	(1,285)	(1,888)	(2,464)	(10)	(2)	(988)	0
Total	8,824,452	355,769	1,341,989	1,664,984	118,329	557,127	1,430,308	764,490	421,499	544,795	779,461	603,207	7,386	587	234,005	515
INCOME TAXES																
Customer	95,324	11,543	34,288	34,186	1,613	4,461	4,494	1,268	644	499	391	428	140	8	1,343	21
Capacity	241,832	2,930	20,395	33,732	3,222	18,341	52,531	29,190	16,148	21,200	29,234	14,737	157	16	0	0
Capacity LV	21,784	0	0	0	0	0	0	0	0	0	1,728	10,850	0	0	9,206	0
Commodity	(659)	(6)	(43)	(63)	(7)	(43)	(122)	(68)	(37)	(52)	(77)	(100)	(0)	(0)	(40)	0
Total	358,280	14,467	54,640	67,854	4,829	22,758	56,903	30,389	16,754	21,647	31,275	25,914	296	23	10,509	21
REVENUE CREDITED TO COS:																
Customer	(1,015,170)	(143,619)	(286,578)	(240,016)	(31,849)	(154,267)	(128,535)	(24,446)	(5,861)							
TOTAL COST OF SERVICE:																
Customer	16,517,001	1,919,055	5,985,318	6,071,949	272,915	711,598	744,776	221,972	119,267	96,993	75,905	43,093	27,211	1,504	34,409	191,034
Capacity	20,627,428	307,294	2,166,310	2,913,928	336,969	1,662,950	4,637,131	2,800,025	1,498,687	1,473,649	1,881,069	922,924	13,348	1,368	11,776	0
Capacity LV	1,390,138	0	0	0	0	0	0	0	0	0	137,999	866,678	0	0	385,462	0
Commodity	2,337,088	23,423	161,945	238,730	25,030	162,550	458,873	257,631	141,028	196,609	288,873	376,889	1,485	268	3,753	0
Subtotal	40,871,655	2,249,772	8,313,573	9,224,607	634,914	2,537,098	5,840,780	3,279,629	1,758,983	1,767,251	2,383,845	2,209,584	42,043	3,140	435,400	191,034
Revenue	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
Total	41,309,820	2,273,890	8,402,699	9,323,500	641,721	2,564,297	5,903,397	3,314,788	1,777,840	1,786,197	2,409,401	2,233,271	42,494	3,174	440,067	193,082

COST OF SERVICE
SUMMARY

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

SUMMARY	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
RATE BASE	119,897,444	4,833,815	18,233,544	22,622,070	1,607,725	7,569,666	19,433,531	10,387,098	5,726,891	7,402,100	10,590,501	8,195,747	100,357	7,979	3,179,421	7,000
ATTRITION	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPERATION AND MAINTENANCE	22,906,545	1,630,091	5,696,717	5,845,437	408,612	1,474,850	2,905,682	1,669,839	864,035	603,483	710,220	856,600	25,872	1,860	22,750	190,498
DEPRECIATION	7,812,458	315,356	1,207,727	1,511,601	108,031	508,565	1,258,381	669,765	369,126	476,330	688,349	575,891	6,792	532	116,013	0
AMORTIZATION EXPENSES	125,328	2,848	13,045	17,333	1,478	8,319	22,260	12,252	6,721	9,129	13,102	13,958	91	12	4,781	0
TAXES OTHER THAN INCOME TAX (SUB TC	1,859,762	74,860	286,034	357,413	25,485	119,746	295,782	157,340	86,710	111,867	161,439	134,013	1,606	126	47,341	0
TAXES OTHER THAN INCOME TAX (REVEN	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
INCOME TAX (TOTAL)	358,280	14,467	54,640	67,854	4,829	22,758	56,903	30,389	16,754	21,647	31,275	25,914	296	23	10,509	21
REVENUE CREDITED TO COST OF SERVIC	(1,015,171)	(143,619)	(286,578)	(240,016)	(31,849)	(154,267)	(128,535)	(24,446)	(5,861)	0	0	0	0	0	0	0
TOTAL COST OF SERVICE (CUSTOMER)	16,517,000	1,919,055	5,985,318	6,071,949	272,915	711,598	744,776	221,972	119,267	96,993	75,905	43,093	27,211	1,504	34,409	191,034
TOTAL COST OF SERVICE (CAPACITY)	22,017,566	307,294	2,166,310	2,913,928	336,969	1,662,950	4,637,131	2,800,025	1,498,687	1,473,649	2,019,068	1,789,601	13,348	1,368	397,238	0
TOTAL COST OF SERVICE (COMMODITY)	2,337,088	23,423	161,945	238,730	25,030	162,550	458,873	257,631	141,028	196,609	288,873	376,889	1,485	268	3,753	0
TOTAL COST OF SERVICE (REVENUE)	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
TOTAL COST OF SERVICE	41,309,819	2,273,890	8,402,699	9,323,500	641,721	2,564,297	5,903,397	3,314,788	1,777,840	1,786,197	2,409,401	2,233,271	42,494	3,174	440,067	193,082
NO. OF CUSTOMERS	101,459	18,549	43,231	33,768	1,229	2,186	1,742	331	79	50	30	12	248	3	1	0
PEAK AND AVERAGE MONTH SALES VOL.	17,090,237	207,066	1,441,302	2,383,814	227,727	1,296,143	3,712,361	2,062,845	1,141,142	1,498,235	2,065,940	1,041,464	11,080	1,118	0	0
ANNUAL SALES	111,219,921	1,048,530	7,249,620	10,686,950	1,120,500	7,276,670	20,541,864	11,533,090	6,313,260	8,801,385	12,931,652	16,871,740	66,480	12,000	6,766,180	0

COST OF SERVICE
DERIVATION OF REVENUE DEFICIENCY

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

COST OF SERVICE BY CUSTOMER CLASS	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
CUSTOMER COSTS	16,517,000	1,919,055	5,985,318	6,071,949	272,915	711,598	744,776	221,972	119,267	96,993	75,905	43,093	27,211	1,504	34,409	191,034
CAPACITY COSTS	22,017,566	307,294	2,166,310	2,913,928	336,969	1,662,950	4,637,131	2,800,025	1,498,687	1,473,649	2,019,068	1,789,601	13,348	1,368	397,238	0
COMMODITY COSTS	2,337,088	23,423	161,945	238,730	25,030	162,550	458,873	257,631	141,028	196,609	288,873	376,889	1,485	268	3,753	0
REVENUE COSTS	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
TOTAL - (includes rev. credit for other inc.)	41,309,819	2,273,890	8,402,699	9,323,500	641,721	2,564,297	5,903,397	3,314,788	1,777,840	1,786,197	2,409,401	2,233,271	42,494	3,174	440,067	193,082
less: REVENUE AT PRESENT RATES excl, other op (in the attrition year)	37,206,908	2,257,377	7,542,760	8,382,007	624,771	2,349,476	5,424,391	2,869,179	1,542,095	1,617,347	2,120,467	1,954,393	26,648	2,660	493,337	0
equals: GAS SALES REVENUE DEFICIENCY	4,102,911	16,513	859,939	941,493	16,950	214,821	479,006	445,609	235,745	168,850	288,934	278,878	15,846	514	(53,270)	193,082
<u>plus: DEFICIENCY DUE TO REVENUE EXPANSION</u>																
REGULATORY ASSESSMENT 5%	33,498	135	7,021	7,687	138	1,754	3,911	3,638	1,925	1,379	2,359	2,277	129	4	(435)	1,576
BAD DEBT 1,3103%	87,800	353	18,402	20,147	363	4,597	10,250	9,536	5,045	3,613	6,163	5,968	339	11	(1,140)	4,132
STATE INCOME TAX 5 5%	361,810	14,907	54,193	68,339	4,701	22,863	58,791	31,030	16,969	23,078	32,042	25,346	148	24	9,200	179
FEDERAL INCOME TAX 34%	2,113,600	87,061	316,579	399,218	27,462	133,560	343,441	181,270	99,131	134,814	187,182	148,064	865	140	53,746	1,047
plus: DEFICIENCY IN OTHER OPERATING REV.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
equals: TOTAL BASE-REVENUE DEFICIENCY	6,699,619	118,990	1,256,134	1,436,883	49,613	377,595	895,398	671,083	358,816	331,734	516,700	460,533	17,328	693	8,102	200,017
<u>UNIT COSTS:</u>																
Customer	13.566	8.621	11.538	14.984	18.503	27.132	35.635	55.842	125.149	161.655	210.846	299.260	9.143	41.785	2,867.412	n/a
Capacity	1.288	1.484	1.503	1.222	1.480	1.283	1.249	1.357	1.313	0.984	0.977	1.718	1.205	1.223		n/a
Commodity	0.0210	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223	0.0006	n/a

COST OF SERVICE
RATE OF RETURN BY CUSTOMER CLASS
(PAGE 1 OF 2: PRESENT RATES)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
REVENUES: (projected test year)																
Gas Sales (due to growth)	37,206,908	2,257,377	7,542,760	8,382,007	624,771	2,349,476	5,424,391	2,869,179	1,542,095	1,617,347	2,120,467	1,954,393	26,648	2,660	493,337	0
Other Operating Revenue	1,015,171	143,619	286,578	240,016	31,849	154,267	128,535	24,446	5,861	0	0	0	0	0	0	0
Total	38,222,079	2,400,996	7,829,338	8,622,023	656,620	2,503,743	5,552,926	2,893,625	1,547,956	1,617,347	2,120,467	1,954,393	26,648	2,660	493,337	0
EXPENSES:																
Purchased Gas Cost	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
O&M Expenses	22,906,545	1,630,091	5,696,717	5,845,437	408,612	1,474,850	2,905,682	1,669,839	864,035	603,483	710,220	856,600	25,872	1,860	22,750	190,498
Depreciation Expenses	7,812,458	315,356	1,207,727	1,511,601	108,031	508,565	1,258,381	669,765	369,126	476,330	688,349	575,891	6,792	532	116,013	0
Amortization Expenses	125,328	2,848	13,045	17,333	1,478	8,319	22,260	12,252	6,721	9,129	13,102	13,958	91	12	4,781	0
Taxes Other Than Income--Fixed	1,859,762	74,860	286,034	357,413	25,485	119,746	295,782	157,340	86,710	111,867	161,439	134,013	1,606	126	47,341	0
Taxes Other Than Income--Revenue	438,165	24,119	89,126	98,892	6,807	27,199	62,616	35,159	18,857	18,946	25,556	23,688	451	34	4,668	2,048
Total Expses excl. Income Taxes	33,142,258	2,047,274	7,292,649	7,830,677	550,413	2,138,678	4,544,721	2,544,354	1,345,448	1,219,755	1,598,665	1,604,150	34,811	2,563	195,553	192,546
INCOME TAXES:	358,280	14,467	54,640	87,854	4,829	22,758	56,903	30,389	16,754	21,647	31,275	25,914	296	23	10,509	21
NET OPERATING INCOME:	4,721,541	339,255	482,050	723,492	101,379	342,306	951,302	318,881	185,754	375,945	490,527	324,329	(8,460)	74	287,275	(192,567)
RATE BASE:	119,897,444	4,833,815	18,233,544	22,622,070	1,607,725	7,569,666	19,433,531	10,387,098	5,726,891	7,402,100	10,590,501	8,195,747	100,357	7,979	3,179,421	7,000
RATE OF RETURN	3.94%	7.02%	2.64%	3.20%	6.31%	4.52%	4.90%	3.07%	3.24%	5.08%	4.63%	3.96%	-8.43%	0.92%	9.04%	-2750.96%

COST OF SERVICE
RATE OF RETURN BY CUSTOMER CLASS
(Page 2 of 2: PROPOSED RATES)

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
REVENUES:																
Gas Sales	43,844,174	2,381,998	8,759,120	9,805,078	669,980	2,719,408	6,320,067	3,527,846	1,891,134	1,968,677	2,638,242	2,427,391	39,692	3,347	493,337	198,858
Other Operating Revenue	1,077,523	152,440	304,180	254,758	33,805	163,742	136,429	25,948	6,221	0	0	0	0	0	0	0
Total	44,921,697	2,534,438	9,063,300	10,059,836	703,785	2,883,150	6,456,496	3,553,794	1,897,355	1,968,677	2,638,242	2,427,391	39,692	3,347	493,337	198,858
EXPENSES:																
Purchased Gas Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M Expenses	22,994,345	1,635,044	5,714,432	5,865,100	409,988	1,480,485	2,918,301	1,676,785	867,743	607,331	715,376	861,344	25,949	1,866	23,714	190,887
Depreciation Expenses	7,812,458	315,356	1,207,727	1,511,601	108,031	508,565	1,258,381	669,765	369,126	476,330	688,349	575,891	6,792	532	116,013	0
Amortization Expenses	125,328	2,848	13,045	17,333	1,478	8,319	22,260	12,252	6,721	9,129	13,102	13,958	91	12	4,781	0
Taxes Other Than Income--Fixed	1,859,762	74,860	286,034	357,413	25,485	119,746	295,782	157,340	86,710	111,867	161,439	134,013	1,606	126	47,341	0
Taxes Other Than Income--Revenue	471,663	26,009	95,884	106,394	7,331	29,349	67,431	37,809	20,272	20,414	27,523	25,498	480	36	5,036	2,196
Total Expses excl. Income Taxes	33,263,556	2,054,118	7,317,121	7,857,841	552,313	2,146,464	4,562,155	2,553,950	1,350,571	1,225,071	1,605,789	1,610,705	34,919	2,572	196,885	193,083
PRE TAX NOI:	11,658,141	480,320	1,746,179	2,201,995	151,472	736,686	1,894,341	999,844	546,784	743,606	1,032,453	816,686	4,773	775	296,452	5,775
INCOME TAXES:	2,833,690	116,455	425,411	535,411	36,991	179,181	459,134	242,689	132,854	179,540	250,499	199,324	1,310	188	73,455	1,247
NET OPERATING INCOME:	8,824,451	363,866	1,320,767	1,666,584	114,481	557,505	1,435,207	757,154	413,929	564,067	781,954	617,363	3,463	587	222,996	4,528
RATE BASE:	119,897,444	4,833,815	18,233,544	22,622,070	1,607,725	7,569,666	19,433,531	10,387,098	5,726,891	7,402,100	10,590,501	8,195,747	100,357	7,979	3,179,421	7,000
RATE OF RETURN	7.36%	7.53%	7.24%	7.37%	7.12%	7.36%	7.39%	7.29%	7.23%	7.62%	7.38%	7.53%	3.45%	7.36%	7.01%	64.68%

COST OF SERVICE SUMMARY
PROPOSED RATE DESIGN

COMPANY NAME: CITY GAS COMPANY OF FLORIDA
DOCKET NO. 030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
PRESENT RATES (projected test year)																
GAS SALES (due to growth)	37,206,908	2,257,377	7,542,760	8,382,007	624,771	2,349,476	5,424,391	2,869,179	1,542,095	1,617,347	2,120,467	1,954,393	26,648	2,660	493,337	0
OTHER OPERATING REVENUE	1,015,171	143,619	286,578	240,016	31,849	154,267	128,535	24,446	5,861	0	0	0	0	0	0	0
TOTAL	38,222,079	2,400,996	7,829,338	8,622,023	656,620	2,503,743	5,552,926	2,893,625	1,547,956	1,617,347	2,120,467	1,954,393	26,648	2,660	493,337	0
RATE OF RETURN	3.94%	7.02%	2.64%	3.20%	6.31%	4.52%	4.90%	3.07%	3.24%	5.08%	4.63%	3.96%	-8.43%	0.92%	9.04%	-2750.96%
INDEX	1.00	1.78	0.67	0.81	1.60	1.15	1.24	0.78	0.82	1.29	1.18	1.00	-2.14	0.23	2.29	-698.57
PROPOSED RATES																
GAS SALES	43,844,174	2,381,998	8,759,120	9,805,078	669,980	2,719,408	6,320,067	3,527,846	1,891,134	1,968,677	2,638,242	2,427,391	39,692	3,347	493,337	198,858
OTHER OPERATING REVENUE	1,077,523	152,440	304,180	254,758	33,805	163,742	136,429	25,948	6,221	0	0	0	0	0	0	0
TOTAL	44,921,697	2,534,438	9,063,300	10,059,836	703,785	2,883,150	6,456,496	3,553,794	1,897,355	1,968,677	2,638,242	2,427,391	39,692	3,347	493,337	198,858
TOTAL REVENUE INCREASE	6,699,618	133,442	1,233,962	1,437,813	47,165	379,407	903,570	660,169	349,399	351,330	517,775	472,998	13,044	687	0	198,858
PERCENT INCREASE	17.53%	5.56%	15.76%	16.68%	7.18%	15.15%	16.27%	22.81%	22.57%	21.72%	24.42%	24.20%	48.95%	25.83%	0.00%	n/a
RATE OF RETURN	7.36%	7.53%	7.24%	7.37%	7.12%	7.36%	7.39%	7.29%	7.23%	7.62%	7.38%	7.53%	3.45%	7.36%	7.01%	64.68%
INDEX	1.00	1.02	0.98	1.00	0.97	1.00	1.00	0.99	0.98	1.04	1.00	1.02	0.47	1.00	0.95	8.79

COST OF SERVICE
CALCULATION OF COMMISSION APPROVED RATES
CITY GAS COMPANY OF FLORIDA
030569-GU

	TOTAL	GS-1	GS-100	GS-220	GS-600	GS-1,200	GS-6K	GS-25K	GS-60K	GS-120K	GS-250K	GS-1250K	GAS LIGHTING	NG VEHICLES	CONTRACT DEMAND	THIRD PARTY SUPPLIER
PROPOSED TOTAL TARGET REVENUES	44,921,697	2,534,438	9,063,300	10,059,836	703,785	2,883,150	6,456,496	3,553,794	1,897,355	1,968,677	2,638,242	2,427,391	39,692	3,347	493,337	198,858
LESS: IMPUTED REVENUES *	280,288	11,863	43,061	54,336	3,732	18,176	46,792	24,686	13,495	18,390	25,494	20,128	113	19	0	0
LESS: OTHER OPERATING REVENUE	1,077,523	152,440	304,180	254,758	33,805	163,742	136,429	25,948	6,221	0	0	0	0	0	0	0
NET TARGET REVENUE	43,563,886	2,370,135	8,716,059	9,750,742	666,248	2,701,232	6,273,275	3,503,160	1,877,639	1,950,287	2,612,748	2,407,263	39,579	3,328	493,337	198,858
LESS: CUSTOMER CHARGE REVENUES																
PROPOSED CUSTOMER CHARGES		$8.00	$9.50	$11.00	$12.00	$15.00	$30.00	$80.00	$150.00	$250.00	$300.00	$500.00	N/A	$15.00	$400.00	$400.00
TIMES: NUMBER OF BILLS	1,217,625	222,591	518,769	405,217	14,750	26,228	20,900	3,975	953	600	360	126	2,976	36	12	132
EQUALS: CUSTOMER CHARGE REVENUES	13,203,931	1,780,728	4,928,306	4,457,387	177,000	393,420	627,000	318,000	142,950	150,000	108,000	63,000	0	540	4,800	52,800
DEMAND CHARGES										$0.289	$0.289	$0.289				$5.92
TIMES: DCQs										721,919	974,586	974,532				24,672
EQUALS DEMAND CHARGE REVENUES	917,988									208,635	281,655	281,640				146,058
EQUALS: PER-THERM TARGET REVENUES	29,441,967	589,407	3,787,753	5,293,355	489,248	2,307,812	5,646,275	3,185,160	1,734,689	1,591,652	2,223,092	2,062,623	39,579	2,788	488,537	
DIVIDED BY: NUMBER OF THERMS	111,219,921	1,048,530	7,249,620	10,686,950	1,120,500	7,276,670	20,541,864	11,533,090	6,313,260	8,801,385	12,931,652	16,871,740	66,480	12,000	6,766,180	
EQUALS: PER-THERM RATES (UNROUNDED)		0.56213	0.52248	0.49531	0.43663	0.31715	0.27487	0.27618	0.27477	0.18084	0.17191	0.12225	0.59535	0.23232	0.07220	
PER-THERM RATES (ROUNDED)		0.56213	0.52248	0.49531	0.43663	0.31715	0.27487	0.27618	0.27477	0.18084	0.17191	0.12225	0.59535	0.23232	0.07220	
PER-THERM-RATE REVENUES (ROUNDED RATES)	29,442,008	589,410	3,787,781	5,293,353	489,244	2,307,796	5,646,342	3,185,209	1,734,694	1,591,642	2,223,080	2,062,570	39,579	2,788	488,518	
SUMMARY: TARIFF RATES																
CUSTOMER CHARGES		$8.00	$9.50	$11.00	$12.00	$15.00	$30.00	$80.00	$150.00	$250.00	$300.00	$500.00	N/A	$15.00	$400.00	$400.00
DEMAND CHARGES										$0.289	$0.289	$0.289				$5.92
NON-GAS ENERGY CHARGES (CENTS PER THERM)		56.213	52.248	49.531	43.663	31.715	27.487	27.618	27.477	18.084	17.191	12.225	59.535	23.232	7.220	
PURCHASED GAS ADJUSTMENT		54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	54.272	
TOTAL (INCLUDING PGA)		110.485	106.520	103.803	97.935	85.987	81.759	81.890	81.749	72.356	71.463	66.497	113.807	77.504	61.492	

~~SUMMARY: OTHER OPERATING REVENUE~~	PRESENT REVENUE	PROPOSED REVENUE
CONNECTION CHARGE	$88,090	$178,980
COLLECTION IN LIEU OF DISCONNECT	$126,894	$257,824
RETURNED CHECK CHARGE	$91,225	$91,225
LATE PAYMENT	$420,000	$420,000
CHANGE OF ACCOUNT	$366,320	$366,320
TOTAL	$1,015,170	$1,077,523
INCREASE		$62,353

* Target revenues are reduced to reflect Commission imputation of $280, 288.

CITY GAS COMPANY OF FLORIDA

DOCKET NO 030569-GU

COMMISSION APPROVED ALLOCATION OF REVENUE INCREASE

(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)	(9)		(10)
			PRESENT		INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF GAS	TOTAL * INCREASE IN REVENUE				REVENUE PERCENTAGE INCREASE
RATE	RATE BASE	PRESENT NOI	ROR	INDEX				REQUIRED NOI	ROR	INDEX	
GS-1	$4,833,815	$339,255	7.02%	1.78	$8,821	$124,621	$133,442	$363,866	7.53%	1.02	5.56%
GS-100	$18,233,544	$482,050	2.64%	0.67	$17,602	$1,216,360	$1,233,962	$1,320,767	7.24%	0.98	15.76%
GS-220	$22,622,070	$723,492	3.20%	0.81	$14,742	$1,423,071	$1,437,813	$1,666,584	7.37%	1.00	16.68%
GS-600	$1,607,725	$101,379	6.31%	1.60	$1,956	$45,209	$47,165	$114,481	7.12%	0.97	7.18%
GS-1,200	$7,569,666	$342,306	4.52%	1.15	$9,475	$369,932	$379,407	$557,505	7.36%	1.00	15.15%
GS-6K	$19,433,531	$951,302	4.90%	1.24	$7,894	$895,676	$903,570	$1,435,207	7.39%	1.00	16.27%
GS-25K	$10,387,098	$318,881	3.07%	0.78	$1,502	$658,667	$660,169	$757,154	7.29%	0.99	22.81%
GS-60K	$5,726,891	$185,754	3.24%	0.82	$360	$349,039	$349,399	$413,929	7.23%	0.98	22.57%
GS-120K	$7,402,100	$375,945	5.08%	1.29	$0	$351,330	$351,330	$564,067	7.62%	1.04	21.72%
GS-250K	$10,590,501	$490,527	4.63%	1.18	$0	$517,775	$517,775	$781,954	7.38%	1.00	24.42%
GS-1250K	$8,195,747	$324,329	3.96%	1.00	$0	$472,998	$472,998	$617,363	7.53%	1.02	24.20%
GAS LIGHTING	$100,357	($8,460)	-8.43%	-2.14	$0	$13,044	$13,044	$3,463	3.45%	0.47	48.95%
NG VEHICLES	$7,979	$74	0.92%	0.23	$0	$687	$687	$587	7.36%	1.00	25.83%
CONTRACT DEMAND **	$3,179,421	$287,275	9.04%	2.29	$0	$0	$0	$222,996	7.01%	0.95	0.00%
THIRD PARTY SUPPLIER ***	$7,000	($192,567)	-2750.96%	-698.57	$0	$198,858	$198,858	$4,528	64.68%	8.79	n/a
TOTAL	**$119,897,444**	**$4,721,541**	**3.94%**	**1.00**	**$62,352**	**$6,637,267**	**$6,699,619**	**$8,824,452**	**7.36%**	**1.00**	**17.53%**

* Total includes imputed revenues of $280,288.

** Rate established by special contract.

*** New rate rate class.

CITY GAS COMPANY OF FLORIDA
COMMISSION APPROVED RATES
DOCKET NO. 030569-GU

RATE SCHEDULES	PRESENT RATES	COMMISSION APPROVED RATES
GS-1 (Residential Service)		
CUSTOMER CHARGE	$7.50	$8.00
ENERGY CHARGE (cents/therm)	49.367	56.213
GS-100 (Residential Service)		
CUSTOMER CHARGE	$7.50	$9.50
ENERGY CHARGE (cents/therm)	49.367	52.248
GS-220 (Residential Service)		
CUSTOMER CHARGE	$7.50	$11.00
ENERGY CHARGE (cents/therm)	49.367	49.531
GS-600 (Residential Service)		
CUSTOMER CHARGE	$7.50	$12.00
ENERGY CHARGE (cents/therm)	49.367	43.663
GS-1.2K (Residential Service)		
CUSTOMER CHARGE	$7.50	$15.00
ENERGY CHARGE (cents/therm)	49.367	31.715
GS-1 (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$8.00
ENERGY CHARGE (cents/therm)	23.877	56.213
GS-100 (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$9.50
ENERGY CHARGE (cents/therm)	23.877	52.248
GS-220 (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$11.00
ENERGY CHARGE (cents/therm)	23.877	49.531

CITY GAS COMPANY OF FLORIDA
COMMISSION APPROVED RATES
DOCKET NO. 030569-GU

RATE SCHEDULES	PRESENT RATES	COMMISSION APPROVED RATES
GS-600 (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$12.00
ENERGY CHARGE (cents/therm)	23.877	43.663
GS-1.2K (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$15.00
ENERGY CHARGE (cents/therm)	23.877	31.715
GS-6K (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$30.00
ENERGY CHARGE (cents/therm)	23.877	27.487
GS-25K (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$80.00
ENERGY CHARGE (cents/therm)	23.877	27.618
GS-60K (Commercial and Industrial Firm Service)		
CUSTOMER CHARGE	$20.00	$150.00
ENERGY CHARGE (cents/therm)	23.877	27.477
GS-1 (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$8.00
ENERGY CHARGE (cents/therm)	23.877	56.213
GS-100 (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$9.50
ENERGY CHARGE (cents/therm)	23.877	52.248
GS-220 (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$11.00
ENERGY CHARGE (cents/therm)	23.877	49.531

CITY GAS COMPANY OF FLORIDA
COMMISSION APPROVED RATES
DOCKET NO. 030569-GU

ATTACHMENT 7
Page 3 of 5

RATE SCHEDULES	PRESENT RATES	COMMISSION APPROVED RATES
GS-600 (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$12.00
ENERGY CHARGE (cents/therm)	23.877	43.663
GS-1.2K (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$15.00
ENERGY CHARGE (cents/therm)	23.877	31.715
GS-6K (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$30.00
ENERGY CHARGE (cents/therm)	23.877	27.487
GS-25K (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$80.00
ENERGY CHARGE (cents/therm)	23.877	27.618
GS-60K (Small Commercial Transportation Service)		
CUSTOMER CHARGE	$25.00	$150.00
ENERGY CHARGE (cents/therm)	23.877	27.477
GS-120K (Large Commercial Service)		
CUSTOMER CHARGE	$50.00	$250.00
ENERGY CHARGE (cents/therm)	17.847	18.084
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-120K (Commercial Transportation Service)		
CUSTOMER CHARGE	$55.00	$250.00
ENERGY CHARGE (cents/therm)	17.847	18.084
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-250K (Interruptible Preferred Gas Service)		
CUSTOMER CHARGE	$100.00	$300.00
ENERGY CHARGE (cents/therm)	15.787	17.191
DEMAND CHARGE ($ per DCQ)	N/A	$0.289

CITY GAS COMPANY OF FLORIDA
COMMISSION APPROVED RATES
DOCKET NO. 030569-GU

RATE SCHEDULES	PRESENT RATES	COMMISSION APPROVED RATES
GS-250K (Contract Interruptible Preferred Gas Service)		
CUSTOMER CHARGE	$100.00	$300.00
ENERGY CHARGE (cents/therm)	15.787	17.191
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-250K (Interruptible Transportation Service)		
CUSTOMER CHARGE	$175.00	$300.00
ENERGY CHARGE (cents/therm)	15.787	17.191
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-250K (Contract Interruptible Transportation Service)		
CUSTOMER CHARGE	$175.00	$300.00
ENERGY CHARGE (cents/therm)	15.787	17.191
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-1,250K (Interruptible Large Volume Gas Service)		
CUSTOMER CHARGE	$250.00	$500.00
ENERGY CHARGE (cents/therm)	11.198	12.225
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-1,250K (Contract Interruptible Large Volume Gas Service)		
CUSTOMER CHARGE	$250.00	$500.00
ENERGY CHARGE (cents/therm)	11.198	12.225
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-1,250K (Interruptible Large Volume Transportation)		
CUSTOMER CHARGE	$400.00	$500.00
ENERGY CHARGE (cents/therm)	11.198	12.225
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GS-1,250K (Contract Interruptible Large Volume Transportation)		
CUSTOMER CHARGE	$400.00	$500.00
ENERGY CHARGE (cents/therm)	11.198	12.225
DEMAND CHARGE ($ per DCQ)	N/A	$0.289
GAS LIGHTING		
ENERGY CHARGE (cents/therm)	49.367	59.535
NATURAL GAS VEHICLES (NGVSS)		
CUSTOMER CHARGE	$15.00	$15.00
ENERGY CHARGE (cents/therm)	17.500	23.232
NATURAL GAS VEHICLES (NGVTS)		
CUSTOMER CHARGE	$15.00	$15.00
ENERGY CHARGE (cents/therm)	17.500	23.232

CITY GAS COMPANY OF FLORIDA
COMMISSION APPROVED MISCELLANEOUS CHARGES
DOCKET NO. 030569-GU

RATE SCHEDULE	PRESENT CHARGES	COMMISSION APPROVED CHARGES
RESIDENTIAL		
CONNECTION CHARGE	$30.00	$50.00
RECONNECTION CHARGE (NON-PAYMENT)	$30.00	$37.00
COMMERCIAL		
CONNECTION CHARGE	$60.00	$110.00
RECONNECTION CHARGE (NON-PAYMENT)	$60.00	$80.00
OTHER		
COLLECTION IN LIEU OF DISCONNECT	$20.00	$20.00
CHANGE OF ACCOUNT	$20.00	$20.00
RETURNED CHECK CHARGE	> $25 or 5%	> $25 or 5%
LATE PAYMENT CHARGE	1.5%	> $5 or 1.5%
TEMPORARY DISCONNECT CHARGE	NO CURRENT CHARGE	NONE
COPY OF TARIFF	$25.00	NONE

Attachment 8

City Gas Company of Florida
Docket No. 030569-GU
Commission Approved Development of Demand Charge per Demand Charge Quantity

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Rate Class	**Annual Allocated Return (NOI) and Depreciation on Capacity Costs**	**Winter Months Capacity Costs**	**Peak Month Consumption (Therms)**	**Peak and Average Month Consumption (Therms)**	**Peak Capacity Contribution Percentage**	**Winter Months Peak Capacity Cost**	**Winter Demand Charge Quantity (Therms)**	**Summer Demand Charge Quantity (Therms)**	**Weighted Average Demand Charge Quantity (Therms)**
GS-120K	$998,148	$415,895	767,920	1,498,235	51.25%	$213,167	67,400	55,097	60,160
GS-250K	$1,450,711	$604,463	1,127,759	2,200,840	51.24%	$309,740	98,530	69,000	81,215
GS-1250k	$1,160,776	$483,657	1,474,656	2,874,391	51.30%	$248,132	83,720	79,560	81,211
Total	**$3,609,635**	**$1,504,015**	**3,370,335**	**6,573,466**	**51.27%**	**$771,039**	**249,650**	**203,657**	**222,586**

	Total
Winter Months Peak Capacity Cost	**$771,039**
Weighted Average Demand Charge Quantity in Therms	**$222,586**
Number of Months	**12**
Monthly Demand Charge per Demand Charge Quantity (Therms)	**$0.289**

Notes:

(2) (1)*5/12, Winter assumed to be 5 months

(5) (3)/(4)

(6) (2)*(5)

(7) and (8) Based on historic consumption for 36-month period ending Sept 30, 2002

(9) (7)*5/12 plus (8)*7/12, Winter season November through March, summer season April through October