ORIGINAL

City Gas Company of Florida

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 000768-GU

DIRECT TESTIMONY AND EXHIBITS

VOLUME II

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBITS OF

ROBERT J. CLANCY, JR.

ON BEHALF OF CITY GAS COMPANY OF FLORIDA

DOCKET NO. 000768-GU

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A. My name is Robert J. Clancy, Jr. My business address is NUI Corporation, One Elizabethtown Plaza, Union, New Jersey 07083.

Q. WHAT IS YOUR POSITION WITH NUI CORPORATION?

A. I am currently employed as Director, Financial Analysis & Revenue Requirements for NUI Corporation ("NUI").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Arts Degree in Economics from Holy Cross College in June 1969 and a Master of Science Degree in Professional Accounting from Northeastern University in September 1970. I am a Certified Public Accountant in the State of New Jersey, and a member of the American Institute of Certified Public Accountants and the New Jersey State Society of Certified Public Accountants. I am also a member of the Accounting and Tax Committee of the New Jersey Utilities Association.

Upon graduation from Northeastern University in 1970, I was employed by Arthur Andersen & Co., in its Newark, NJ office. My experience with this public accounting firm included auditing engagements on a variety of industrial companies and exposure to varied accounting and financial reporting systems.

In October 1971, I was hired as a Staff Accountant by National Utilities & Industries Corporation - now NUI. I was promoted to Supervisor of Accounting in November 1975 and Manager of Accounting in July 1978. My responsibilities with NUI included the supervision of all general accounting functions for the holding company and a group of subsidiaries, the consolidation, and all financial reporting to management, shareholders and the Securities and Exchange Commission.

In March 1981, I became Director of General Accounting for Elizabethtown Gas Company, which was then NUI's largest subsidiary, and subsequently was promoted to Controller in May 1988, to Assistant Vice President of Accounting in February 1994 and, in January 1998, to Vice President, Financial Planning & Analysis. In July 1998, I became Assistant Controller for NUI Corporation, and in October 1999 I was made Director, Financial Analysis & Revenue Requirements.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will support the Company's request for permanent and interim rate relief and describe how the test year was constructed. I will also sponsor the various Minimum Filing Requirements ("MFR") schedules that I prepared or that were prepared under my supervision

Q. HAVE YOU PREPARED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. They are attached as Exhibits No. ____ (RJC-1) through No. ____ (RJC-5).

Q. PLEASE IDENTIFY THE MFR SCHEDULES YOU ARE SPONSORING.

A. The MFRs I am sponsoring are listed in Exhibit No. ____ (RJC-1).

INTERIM INCREASE

Q. ON WHAT HISTORICAL PERIOD IS CITY GAS' REQUEST FOR AN INTERIM INCREASE IN RATES BASED?

A. The historical period is the 12-month period ended September 30, 1999.

Q. WHAT IS THE SIZE OF THE INTERIM INCREASE CITY GAS IS REQUESTING IN THIS CASE?

A. City Gas requests that annual revenues be increased by $1,886,605 on an interim basis, to $31.2 million. This represents a 6.05% increase in base rates.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THIS AMOUNT.

A. The Revenue Deficiency for the interim increase is calculated on Schedule F-7 of the MFRs, based on an Adjusted Rate Base of $95,400,342 and a Requested Rate of Return of 6.99%, yielding a Net Operating Income ("NOI") Requirement of $6,678,024. The calculation of Adjusted Rate Base is presented on Schedule F-1 of the MFRs and the Requested Rate of Return calculation is presented on Schedule F-8. The Company's Adjusted NOI for the 12 months ended September 30, 1999 was $5,474,979, which was calculated on Schedule F-4. The NOI Deficiency is $1,161,989, which is the difference between the NOI Requirement and the Company's Adjusted NOI. The requested interim increase of $1,886,605 equals the NOI Deficiency grossed up by an Expansion Factor of 1.6236 as calculated on Schedule F-7.

Q. HAS THE INTERIM INCREASE BEEN CALCULATED IN ACCORDANCE WITH THE COMMISSION'S REQUIREMENTS?

A. Yes. I have reviewed Rule 25-7.040, Florida Administrative Code, and Section 366.071, Florida Statutes, regarding interim awards. In my opinion, the Company's requested interim award has been calculated in a manner consistent with Commission policy governing such awards.

In particular, the calculations of Rate Base, Requested Rate of Return and Adjusted NOI reflect all adjustments required to be consistent with those made by the Commission in City Gas' last rate case (Docket No. 960502-GU), except that the adjustments have been updated to reflect the actual amounts for the historical period. In addition, the Requested Rate of Return is based on a cost of equity that is at the low end of the Company's last authorized rate of return.

PROJECTED TEST YEAR

Q. ON WHAT PROJECTED TEST PERIOD IS CITY GAS' REQUEST FOR A PERMANENT CHANGE IN BASE RATES BASED?

A. The projected test period consists of the 12 months ending September 30, 2001. In accordance with the Commission's requirements, the MFRs include financial information for the historical base year (1999) as well as information for the "base year plus 1" (2000) and the projected test year.

Q. IN YOUR OPINION, IS THE PROJECTED 2001 TEST YEAR AN APPROPRIATE TEST PERIOD FOR SETTING RATES?

A. Yes. The year ending September 30, 2001 best reflects the number of customers, sales levels and overall cost of service that NUI City Gas will experience at the time that rates set in this proceeding will be in effect. Since this period coincides with the Company's fiscal year, it allows us to use the budgeting process to help forecast our capital additions, sales and transportation volumes, and operating expenses.

Q. PLEASE DESCRIBE HOW YOU CONSTRUCTED THE TEST YEAR DATA.

A. The test year projections were developed in two ways. Rate base and margins were a product of NUI City Gas' budgeting process for 2001. Projections for 2001 of margins (revenues less gas costs and taxes on revenues) were developed using actual customer numbers as of May 2000 and the Company's analysis of market trends to forecast customer levels in 2001. These customer numbers were then used to calculate the gas demand forecast. This process is described in detail in the testimony of company witness Len Willey, Jr. Rate base was also projected based on capital spending requirements identified by City Gas' operational managers and other additions developed as part of the 2001 budget, to the extent available. The Company's 2001 budget has not yet been finalized.

The second method used pertained to operating expenses. Due to the incompleteness of the operating expense budget for 2001, the 2001 projections were prepared by trending the 1999 historical year expense levels for expected cost increases, and reflecting certain planned operational changes and known cost differences. Actual expenses to date for 2000 also were reviewed to check the reasonableness of the results.

Q. PLEASE DESCRIBE HOW THE MARKET GROWTH REFLECTED IN THE TEST YEAR WAS DERIVED.

A. Market growth that is reflected in the projections of revenues in the test year was projected by the Company's Marketing Department in the course of the budgeting process for fiscal 2001. The marketing information was provided to the Company's Energy Planning Department, which is responsible for preparing the forecast of customer demand and revenues. The development of the revenue forecast is described in the testimony of company witness Leonard J. Willey.

Q. COULD YOU DESCRIBE HOW THE CAPITAL SPENDING PROJECTIONS USED TO CALCULATE RATE BASE WERE PREPARED.

A. The capital spending projections were prepared under the supervision of company witness Rick Wall and are sponsored by him. I have reviewed those projections and included them in the calculation of the Rate Base.

With respect to spending on new business projects, the capital spending projections are tied directly to the market growth projections developed by NUI's Marketing Department. The capital spending projections also reflect the Company's expectations regarding spending for system improvements and other expenditures, including non-operating capital requirements, such as office improvements.

The capital spending projections reflect the Company policy of requiring a stringent review of cost-effectiveness before any capital dollars are committed.

Q. PLEASE DESCRIBE THE REVIEW TO WHICH YOU REFER.

A. NUI has established procedures to ensure a proper assessment of the financial and strategic feasibility of each proposed capital project. With regard to NUI City Gas, the procedure requires compliance with its Commission-approved expansion tariff, in addition to the Company's requirements. The process imposes a discipline on the entire sales and construction functions that is reflected in the establishment of marketing goals and capital spending budgets.

Q. PLEASE DESCRIBE THE REQUIRED ANALYSIS OF PROPOSED EXTENSIONS.

A. Using a model developed for the purpose, the Marketing and Engineering departments examine a proposed extension to determine whether, on a net present value basis, the return to be derived meets or exceeds the Company's incremental cost of capital. If a project can reasonably be expected to earn its cost of capital it is submitted to the Divisional Manager and Regional Sales manager for their review and approvals. Projects with costs of $150,000 or more are submitted to the Directors of Marketing and Operations for their approvals. Projects in excess of $250,000 require the approval of the Vice President of Distribution Services or the Treasurer. Division Managers are then held accountable to hold project costs to budgets.

Q. HOW DOES THIS REVIEW RELATE TO THE COMPANY'S EXTENSION OF FACILITIES TARIFF, WHICH ALLOWS EXTENSIONS EQUIVALENT TO SIX TIMES THE ESTIMATED ANNUAL REVENUE TO BE RECEIVED?

A. We perform both analyses for each project. We have seen instances in which the tariff requires us to collect contributions in aid of construction, even though our model indicates the project would earn its cost of capital without collecting aid. Of course, if a customer requests an extension that meets the standard of the tariff, we will provide it.

RATE BASE

Q. WHAT IS THE IMPACT ON RATE BASE IN THE PROJECTED TEST YEAR OF CITY GAS' CAPITAL EXPENDITURE REQUIREMENTS FOR FISCAL 2000 AND 2001?

A. Projected utility capital spending is detailed on Schedule G-1, and amounts to $7.6 million for the historical base year plus one (page 23) and $27.6 million for the projected test year (page 26). These outlays have been scheduled by month in accordance with management's expectations as to the timing of the actual expenditures. The MFRs reflect these as additions to construction work in progress ("CWIP") in the month in which the spending is expected to occur; in turn, the MFRs reflect these expenditures as transfers from CWIP to Gas Plant in Service approximately one month after the construction project is completed, reflecting the placement of the underlying facilities in actual service. Average Rate Base is calculated reflecting the expected timing of these expenditures and their impact on CWIP and plant balances.

Q. IS CITY GAS SEEKING TO INCLUDE IN RATE BASE OR NOI ANY PORTION OF THE ACQUISITION ADJUSTMENT THAT AROSE IN CONNECTION WITH THE ACQUISITION OF CITY GAS BY NUI?

A. No. Adjustments are included on Schedule G-1, page 4, to remove this acquisition adjustment from Adjusted Rate Base. The amortization of the NUI acquisition adjustment is recorded in FERC account 425, which is not a component of NOI, therefore no adjustment is needed.

Q. HOW HAS THE COMPANY TREATED ACQUISITION ADJUSTMENTS RELATED TO ITS VARIOUS PURCHASES OF DISTRIBUTION FACILITIES?

A. The Company has included in Rate Base the acquisition adjustments recorded on the purchases of distribution systems and facilities, consistent with the Commission's treatment of these costs in the last rate case. These include purchases from the Ft. Pierce Utility Authority, Western Energy and

Consolidated Gas, and a negative adjustment related to the acquisition of distribution assets from Miller Gas Company. In Docket No. 960502-GU, the Commission approved the inclusion of these acquisition adjustments in Rate Base because the acquisitions benefited City Gas' customers by increasing throughput and thus spreading the Company's fixed costs over greater sales volumes. In addition, the propane systems that were converted to natural gas by City Gas resulted in lower rates to the former propane customers, greater reliability and the benefits of regulatory protection.

Q. HAS CITY GAS RECORDED ANY ACQUISITION ADJUSMENTS SINCE ITS LAST RATE CASE AND, IF SO, HOW HAVE THEY BEEN TREATED IN THIS FILING?

A. Yes. Three additional purchases have resulted in acquisition adjustments being recorded. These were the GDU propane system in Port St. Lucie, the Homestead Lateral and the Vero Beach Lateral. Consistent with the Commission's treatment of prior acquisition adjustments, these costs have been included in Rate Base. These purchases represent a cost-effective means of growing the Company's customer base, as well as improving system reliability. Please refer to the testimony of company witnesses Rick Wall and Richard Gruber for further discussions of the benefits of these purchases to our customers.

Q. HAVE LEASED APPLIANCES BEEN PROPERLY EXCLUDED FROM RATE BASE AND NOI IN ACCORDANCE WITH ORDER PSC-94-1570-

FOF-GU?

A. Yes. In accordance with the order, all leased appliances, associated accumulated depreciation, and related lease receivables and merchandise inventories have been excluded from utility assets and Adjusted Rate Base, by adjustment on Schedule G-1, page 4. In addition, the adjustments to working capital and to common plant for the calculation of Adjusted Rate Base included provisions to exclude components that help support the leased appliance business. All lease revenues, operating expenses and depreciation directly chargeable to the leasing business are accounted for as Other Income and Expenses for regulatory reporting and, thus, are excluded from the calculation of NOI. In addition, the calculation of the Company's Adjusted NOI includes adjustments to exclude the appropriate portion of Administrative and General ("A&G") expenses that support the leased appliance business.

Q. HAS CITY GAS IDENTIFIED AND EXCLUDED FROM RATE BASE THOSE PORTIONS OF ITS COMMON PLANT THAT ARE PROPERLY APPLICABLE TO ITS NON-UTILITY OPERATIONS?

A. Yes. NUI has performed a thorough study of NUI City Gas' common plant. That study was the basis for the adjustments made to common plant and accumulated depreciation in Rate Base and depreciation expense, which are reflected on pages 18 through 22 of Schedule G-1 and page 28 of Schedule G-2.

Q. WHAT IS THE APPROPRIATE PROJECTED TEST YEAR GAS PLANT

IN SERVICE FOR CITY GAS?

A. The appropriate adjusted Gas Plant is $175,285,811 reflecting the adjustments described above.

Q. WHAT ARE THE APPROPRIATE DEPRECIATION RATES TO BE USED BY CITY GAS FOR THE PROJECTED TEST YEAR?

A. The appropriate depreciation rates are those prescribed in Order No. PSC-99-2505-PAA-GU, issued in Docket No. 990229-GU on December 21, 1999. Those rates have been utilized in this filing.

Q. WHAT ARE THE APPROPRIATE PROJECTED TEST YEAR DEPRECIATION AND AMORTIZATION RESERVES FOR NUI CITY GAS?

A. The appropriate projected test year depreciation and amortization reserves for NUI City Gas amount to $68,135,475, and are deducted from Gas Plant in Service to arrive at Utility Plant, net. These reserves reflect all appropriate adjustments with respect to non-utility operations and disallowances.

Q. WERE FUEL COST OVER/UNDERRECOVERIES PROPERLY EXCLUDED FROM THE WORKING CAPITAL ALLOWANCE FOR THE PROJECTED TEST YEAR?

A. Yes. Underrecovered gas costs were removed from working capital by adjustment on Schedule G-1, page 2.

Q. HAVE COMPONENTS OF WORKING CAPITAL APPLICABLE TO NON-UTILITY OPERATIONS BEEN PROPERLY EXCLUDED FROM THE WORKING CAPITAL ALLOWANCE?

A. Yes. Specific assets related to non-utility operations (e.g., lease receivables and merchandise) were removed from working capital. In addition, provision has been made to exclude from working capital the appropriate portion of common assets apportionable to non-utility activities. The basis for the allocation was the three-factor method that is used by NUI to allocate shared services to its various business units. This allocation methodology is described below. The share of total City Gas costs applicable to its non-utility operations was 12.5%.

Q. WHAT IS THE APPROPRIATE WORKING CAPITAL ALLOWANCE FOR THE PROJECTED TEST YEAR?

A. The appropriate Working Capital Allowance, calculated using the Balance Sheet Method, is $3,836,434, which reflects the adjustments described above.

Q. WHAT IS THE APPROPRIATE ADJUSTED RATE BASE FOR THE PROJECTED TEST YEAR?

A. The appropriate Adjusted Rate Base for the projected test year is $113,986,770. Attached as Exhibit No.____ (RJC-2) is Schedule G-1, page 1, which presents the components of Rate Base.

<u>NET OPERATING INCOME</u>

Q. WHAT IS THE APPROPRIATE AMOUNT OF OPERATING REVENUES FOR THE PROJECTED TEST YEAR?

A. The appropriate amount of Operating Revenues for the projected test year is $33,574,637.

Q. WERE THE COST OF GAS, CONSERVATION COSTS AND REVENUE RELATED TAXES PROPERLY REMOVED FROM REVENUES FOR THE PROJECTED TEST YEAR?

A. Yes. The appropriate amount of Operating Revenues is determined after adjustments to exclude the Cost of Gas, billings for Conservation Costs and billings for taxes collectible from customers. Also, regulatory assessment fees applicable to billings for the Cost of Gas and Conservation are excluded from Taxes Other Than Income by appropriate adjustment.

Q. WHAT IS THE APPROPRIATE O&M BENCHMARK VARIANCE FACTOR FOR CITY GAS?

A. The appropriate benchmark variance factor is 1.1385, 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' last rate case (1995) to the current case historical base year (1999). The calculation of this benchmark variance factor is presented on MFR Schedule C-37.

Q. HAS CITY GAS JUSTIFIED ITS O&M BENCHMARK VARIANCES?

A. Yes. The rate of increase in City Gas' operation and maintenance expenses from 1995 to 1999 was less than the benchmark variance factor in total. The details of variances of actual expenses in the historical base year from the benchmark by function are presented in MFR Schedule-38. Distribution, sales and customer accounts expenses all totaled less in 1999 than the 1995 expenses inflated by the benchmark variance factor. Only A&G expenses reflect a variance in excess of the benchmark. This variance, which is attributable to Outside Services expenses, relates to an increase in the allocation of the costs of corporate shared services to City Gas. This reflects the transfer to NUI of certain additional services that had been performed by City Gas personnel. The efficiencies achieved by centralizing these services are part of the reason for the overall favorable variance in actual base year O & M expenses to the benchmark.

Q. YOU MENTIONED EARLIER THAT THE 2001 OPERATING EXPENSE PROJECTIONS WERE PREPARED BY TRENDING HISTORICAL 1999 DATA AND MAKING ADJUSTMENTS FOR KNOWN CHANGES. PLEASE DESCRIBE THIS PROCESS IN MORE DETAIL.

A. The trending was done in two parts. All O&M expenses were divided between labor and other expenses. A percentage increase was calculated for each group of expenses. This percentage was then compounded for a two-year period and applied to the 1999 expenses in each functional area to derive the projected test year amounts.

An annual increase of 4% was used for all labor expenses. This represents the actual average percentage increase used to determine employee salaries in 2000. It is also the amount used in the preparation of the Company's 2001 operating budget, which has not yet been completed. It is expected that this percentage will be used to calculate wage and salary increases in 2001. After compounding, the labor rate increase used to determine 2001 labor expense was 8.16%.

Non-labor expenses were trended using a rate of 3%, which was calculated using the annual increase in the CPI as of May 2000. The compounded rate of increase used for the two-year period was 6.09%. There was no additional adjustment made to this factor to consider customer growth.

For those operations areas that have or will experience changes in staffing or reflect other fundamental differences in cost structure in 2001, as compared with 1999, costs were removed from the trended expenses for specific costing. These expenses were separately projected for 2001, in most cases by use of the budgeting process. The Company has also identified certain expenses that are expected to be materially higher or lower than the trended level of expense, and specifically forecast them.

Q. COULD YOU DESCRIBE THE MAJOR EXPENSES THAT WERE DETERMINED OTHER THAN BY TRENDING.

A. O&M expenses that were developed by specific examination of the expected costs in 2001 rather than by trending include uncollectible accounts expense, customer billing, postage, benefits costs, the amortization of deferred piping and the cost of the City Gas Call Center, which has recently been consolidated with similar operations of NUI's New Jersey utility.

Uncollectible accounts expense reflects an increase of $332,000 from 1999 to 2001. This increase is a result of a significant deterioration in the Company's customer account collections in 2000 and its current delinquencies in its Miami division. Write-offs for the past year have been running substantially over the historical experience, which was the basis for the uncollectibles provision in 1999. The Company recognized in 1999 that its write-offs were not keeping up with delinquencies and that the allowance for uncollectibles was inadequate. The higher expense levels in 2000 and projected for 2001 represent amounts that will produce adequate allowance balances. Please refer to the testimony of company witness Richard Gruber for a discussion of the initiatives being taken to address this problem.

Expenses for customer billing and postage reflect increased customer contact, in large part related to higher delinquencies. The Company has specific estimated cost information on medical insurance, pension and other employee benefits expenses for 2001 that have been used, rather than trended amounts. Actual amortizations, including reduced amounts for deferred piping, have been included in the projected test year expenses. We have also projected the expenses associated with the new Call Center operations, which have recently been consolidated with New Jersey operations in Hialeah. Costs of this operation, which now provides expanded seven-days-a-week service to our customers, are now incurred by City Gas and reduced by billings to NUI Elizabethtown Gas for their share of the operations.

Q. WHAT IS THE APPROPRIATE AMOUNT OF RATE CASE EXPENSE

AND THE APPROPRIATE AMORTIZATION PERIOD?

A. The Company's calculation of rate case expense for the current case is included on Schedule C-13. The projection amounts to $369,000, which includes $75,000 in the event a hearing is required to resolve this case. This amount should be amortized over a period of three years.

Q. WHAT IS THE APPROPRIATE AMOUNT OF ADVERTISING AND SALES EXPENSE FOR THE PROJECTED TEST YEAR?

A. The O&M for the projected test year includes $928,121 for advertising and sales expenses, including $412,719 for the amortization of deferred interior home piping costs. These expenses support the Company's efforts to promote customer retention and growth by improving customer awareness of the environmental and economic benefits of the use of natural gas. Specifically, the Company will be developing the residential and commercial markets in the areas of expansion, including Port St. Lucie, Vero Beach, the Homestead area, and in Palm Beach and Glade Counties along the new Clewiston Expansion Project distribution line.

Q. HAS NUI CITY GAS PROPERLY IDENTIFIED AND EXCLUDED FROM O&M THOSE PORTIONS OF ITS A&G EXPENSES THAT ARE APPLICABLE TO ITS NON-UTILITY OPERATIONS?

A. Yes. The adjustment is shown on MFR Schedule G-2, page 2.

Q. COULD YOU PLEASE EXPLAIN HOW COSTS ARE ALLOCATED TO CITY GAS FOR NUI CENTRAL SERVICES.

A. Costs for central services provided by NUI have been allocated in accordance with NUI's cost allocation policy. This was also the basis for allocations to City Gas that were incorporated into operating expenses in the Company's last base rate case. The cost allocation methodology used is reflective of the relative size of the individual business units that benefit from the services. In order to give recognition to relative size, the policy and methodology for cost allocation is to use a three-part formula with equal weighting to each component. The factors used are (1) direct payroll, (2) 13-month average plant balance and (3) 13-month average number of customers.

Q. IN ACCORDANCE WITH NUI'S POLICY, WHAT IS THE APPROPRIATE PROPORTION OF NUI CORPORATE EXPENSES TO BE BORNE BY NUI CITY GAS' UTILITY OPERATIONS?

A. Based on the three-factor method described above, 20% of these expenses are reflected in NUI City Gas' cost of service related to its regulated activities.

Q. COULD YOU DESCRIBE THE CENTRAL SERVICES PROVIDED BY NUI FOR WHICH THESE COSTS ARE ALLOCATED?

A. Yes. The services provided include general executive management, treasury, shareholder relations, corporate communications, internal audit, purchasing, legal affairs, accounting, information systems management, risk management, gas supply management, human resources, marketing services, engineering, customer billing, environmental compliance, rates and regulatory affairs. Each of these areas comprises services that City

Gas would have to provide itself if they were not obtained from the corporate headquarters. In many instances NUI City Gas would not be able to afford, on a stand-alone basis, the depth of talent and expertise that NUI can provide on a centralized basis.

Q. WHAT IS THE APPROPRIATE AMOUNT OF NUI CENTRAL SERVICES EXPENSES FOR INCLUSION IN CITY GAS' O&M EXPENSES FOR THE PROJECTED TEST YEAR?

A. The appropriate amount of NUI central services expenses is $5,736,979. This amount is included in Outside Services (Account 923) as part of the Company's O&M expenses for the projected test year.

Q. WHAT IS THE APPROPRIATE AMOUNT OF PROJECTED TEST YEAR O&M EXPENSE, INCLUDING ALLOCATED EXPENSES OF NUI CENTRAL SERVICES?

A. The appropriate amount of O&M for the Projected Test year is $19,594,080, which is included in Operating Expenses used to calculate Net Operating Income on Schedule G-2, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF TAXES OTHER THAN INCOME TAXES TO BE INCLUDED IN THE PROJECTED TEST YEAR?

A. The appropriate amount of taxes other than income taxes is $2,523,303, which is included in Operating Expenses used to calculate Net Operating Income on Schedule G-1, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF INCOME TAX EXPENSE FOR THE PROJECTED TEST YEAR, INCLUDING INTEREST

SYNCHRONIZATION?

A. The appropriate amount of Income Tax Expense, including an adjustment for interest synchronization, for the projected test year is a credit of $81,193, which is presented by component on Schedule G-2, page 1.

Q. WHAT IS THE APPROPRIATE AMOUNT OF NOI FOR THE PROJECTED TEST YEAR?

A. The appropriate amount of NOI for the projected test year, as adjusted for the items described above, is $4,571,159. I have attached a copy of Schedule G-2, page 1, which presents the calculation of this amount, as Exhibit No. ____ (RJC-3).

<u>CAPITAL STRUCTURE</u>

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. The information appears on MFR Schedule G-3, page 2, a copy of which is attached as Exhibit No. ___ (RJC-4).

Q. HAVE YOU PREPARED THE COMPANY'S CAPITAL STRUCTURE FOR RATEMAKING PURPOSES CONSISTENTLY WITH THE MANNER IN WHICH IT WAS APPROVED IN THE LAST RATE CASE?

A. Yes. In the Company's last rate case, the Commission approved the use of NUI's consolidated capital structure as the appropriate one to use for ratemaking purposes. The Company has followed that approach in this case, with one significant modification.

Q. COULD YOU DESCRIBE THE MODIFICATION AND THE REASON FOR IT.

A. During fiscal 2001 NUI will restructure itself as a holding company with two wholly-owned subsidiaries. NUI City Gas will emerge as a division of NUI Utilities, Inc., which will contain all regulated operations of NUI. The non-regulated business units will be separated from the utility operations under a separate NUI subsidiary. The capital structure used in the projected test year reflects that of NUI Utilities, Inc.

The Company believes that this capital structure is more appropriate for a regulated gas utility, since it does not include capital associated with NUI's non-regulated businesses. Under the new corporate organization, the debt/equity ratio of NUI Utilities, Inc. can be maintained at a level that is appropriate for utility financing. By insulating the utility company from the non-regulated operations it is expected that the debt rating of this company will not be negatively affected by the higher risk level associated with the non-regulated business activities. The appropriateness of using NUI Utilities' capital structure is also discussed by Dr. Roger Morin in his filed testimony.

Q. WHAT DEBT/EQUITY RATIO DID YOU EMPLOY?

A. The calculation of capital structure reflects investor sources of capital as follows: Equity, 43.38%, Long-Term Debt, 50.67%, and Short-Term Debt, 5.95%.

Q. ON WHAT IS THE AMOUNT OF EQUITY BASED?

A. The amount of equity is based on the projected weighted average balance of common equity of NUI Utilities, Inc. on a consolidated basis for the projected test year, reduced by the amount invested in the non-utility operations of the Company.

Q. HOW DOES THIS COMPARE TO THE AMOUNT OF EQUITY THAT WAS IN THE CAPITAL STRUCTURE IN THE LAST CASE?

A. Equity in the Company's last base rate case comprised 41.72% of investor sources of capital.

Q. WHAT IS THE APPROPRIATE LEVEL OF CUSTOMER DEPOSITS TO BE USED IN THE DETERMINATION OF NUI CITY GAS' CAPITAL STRUCTURE FOR THE PROJECTED TEXT YEAR?

A. The appropriate level of Customer Deposits to be included in the determination of City Gas' capital structure is $5,596,459, which is the average level of customer deposits for the projected test year.

Q. WHAT IS THE APPROPRIATE LEVEL OF DEFERRED INVESTMENT TAX CREDITS TO BE USED IN THE DETERMINATION OF CITY GAS' CAPITAL STRUCTURE FOR THE PROJECTED TEST YEAR?

A. The appropriate level of Deferred Investment Tax Credits to be included in the determination of NUI City Gas' capital structure is $883,654.

Q. WHAT IS THE APPROPRIATE LEVEL OF DEFERRED INCOME TAXES TO BE USED IN THE DETERMINATION OF CITY GAS' CAPITAL STRUCTURE FOR THE PROJECTED TEST YEAR?

A. The appropriate level of Deferred Income Taxes to be included in the determination of NUI City Gas' capital structure is $10,488,832. This amount was calculated by taking the actual balance on the Company's books as of May 31, 2000 and projecting it forward through September 30, 2001, and adjusting out non-utility related items.

Q. DOES CITY GAS' CAPITAL STRUCTURE FOR RATEMAKING PURPOSES FOR THE PROJECTED TEST YEAR PROPERLY EXCLUDE NON-UTILITY INVESTMENTS?

A. Yes. As discussed above, the non-regulated business activities of NUI will now be operated under a separate subsidiary and are excluded from the capital structure of NUI Utilities, Inc. In addition, the investment in the leasing and merchandising activities of NUI City Gas has been excluded in a manner consistent with the last rate order.

Q. WHAT IS THE APPROPRIATE COST RATE FOR COMMON EQUITY?

A. The appropriate cost rate for Common Equity is 11.7%, as described by Dr. Roger Morin in his filed testimony.

Q. WHAT IS THE APPROPRIATE COST RATE FOR LONG-TERM DEBT?

A. The appropriate cost rate for Long-Term Debt is 6.54%, which is the projected embedded rate for NUI Utilities, Inc.

Q. WHAT IS THE APPROPRIATE COST RATE FOR SHORT-TERM DEBT?

A. The appropriate cost rate for Short-Term Debt is 8%, which is the projected embedded rate for NUI Utilities, Inc.

Q. WHAT IS THE APPROPRIATE COST RATE FOR CUSTOMER DEPOSITS?

A. The appropriate cost rate for Customer Deposits is 6.73%. This is a weighted average rate of 6% paid by City Gas on residential customer deposits and 7% on commercial deposits in accordance with NUI City Gas' tariff.

Q. WHAT IS THE APPROPRIATE COST RATE FOR INVESTMENT TAX CREDITS AND DEFERRED INCOME TAXES?

A. Deferred Investment Tax Credits and Deferred Income Taxes are included in the capital structure without cost.

Q. WHAT IS THE APPROPRIATE WEIGHTED AVERAGE COST OF CAPITAL FOR CITY GAS FOR RATEMAKING PURPOSES FOR THE PROJECTED TEST YEAR?

A. NUI City Gas' appropriate weighted average overall cost of capital for the projected test year is 7.88%.

Q. WHAT IS THE APPROPRIATE REVENUE EXPANSION FACTOR FOR THE PROJECTED TEST YEAR?

A. The appropriate revenue expansion factor is 1.6282, as calculated on schedule G-4.

Q. WHAT IS THE REVENUE DEFICIENCY FOR THE PROJECTED TEST YEAR?

A. The revenue deficiency for NUI City Gas for the projected test year, is calculated on Schedule G-5 of the MFRs, which is included as Exhibit No. ____ (RJC-5). It amounts to $7,181,988, or 21.39%, bringing total operating revenues to $40.757 million. This is the amount of increase that the Company requires in order to give it the opportunity to earn a fair rate of return based on conditions during the projected test year. This deficiency amount has been used as the basis for the rates developed by company witness Thomas Smith, as presented in his testimony.

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes.

MFR SCHEDULES SPONSORED BY
ROBERT J. CLANCY, JR.

SCHEDULE NO.	TITLE
A-1 p. 1	MAGNITUDE OF CHANGE-PRESENT vs. PRIOR RATE CASE
A-2 p. 1	ANALYSIS OF PERMANENT RATE INCREASE REQUESTED
A-3 p. 1	ANALYSIS OF JURISDICTIONAL RATE BASE
A-4 p. 1	ANALYSIS OF JURISDICTIONAL N. O. I.
A-5 p. 1	OVERALL RATE OF RETURN COMPARISON
A-6 p. 1	FINANCIAL INDICATORS
B-1 p.1	BALANCE SHEET – ASSETS
B-1 p.2	BALANCE SHEET - LIABILITIES & CAPITALIZATION
B-2 p.1	ADJUSTED RATE BASE
B-3 p.1	RATE BASE ADJUSTMENTS
B-4 p.1	MONTHLY UTILITY PLANT BALANCES
B-6 p.1	ACQUISITION ADJUSTMENTS
B-6 p.2	ACQUISITION ADJUSTMENTS (CONT.)
B-7 p.1	PROPERTY HELD FOR FUTURE USE
B-7 p.2	PROPERTY HELD FOR FUTURE USE - DETAIL
B-9 p.1	ACCUMULATED DEPRECIATION - MONTHLY BALANCES
B-10 p.1	ACCUMULATED AMORTIZATION – MONTHLY BALANCES
B-12 p.1	CUSTOMER ADVANCES FOR CONSTRUCTION
B-13 p.1	WORKING CAPITAL ALLOWANCE - ASSETS
B-13 p.2	WORKING CAPITAL ALLOWANCE - LIABILITIES
B-14 p.1	MISCELLANEOUS DEFERRED DEBITS
B-15 p.1	OTHER DEFERRED CREDITS
B-16 p.1	ADDITIONAL RATE BASE COMPONENTS
B-17 p.1	INVESTMENT TAX CREDITS - 3% AND 4% ITC DETAIL
B-17 p.2	INVESTMENT TAX CREDITS - 8% AND 10% ITC DETAIL
B-17 p.3	INVESTMENT TAX CREDITS - COMPANY POLICIES
B-17 p.4	INVESTMENT TAX CREDITS - SECTION 46(f) ELECTION
B-18 p.1	ACCUMULATED DEFERRED INCOME TAX - SUMMARY
B-18 p.2	ACCUMULATED DEFERRED INCOME TAX - STATE
B-18 p.3	ACCUMULATED DEFERRED INCOME TAX - STATE
B-18 p.4	ACCUMULATED DEFERRED INCOME TAX - FEDERAL
B-18 p.5	ACCUMULATED DEFERRED INCOME TAX - FEDERAL
C-1 p.1	ADJUSTED NET OPERATING INCOME
C-2 p.1	ADJUSTMENTS TO NET OPERATING INCOME
C-2 p.2	ADJUSTMENTS TO NET OPERATING INCOME - (CONT.)
C-3 p.1	OPERATING REVENUES BY MONTH
C-4 p.1	UNBILLED REVENUES
C-5 p.1	O & M EXPENSES BY MONTH
C-5 p.2	O & M EXPENSES BY MONTH - (CONT.)
C-7 p.1	CONSERVATION REVENUES AND EXPENSES
C-8 p.1	UNCOLLECTIBLE ACCOUNTS - GAS
C-8 p.2	UNCOLLECTIBLE ACCOUNTS - GAS (CONT.)
C-8 p.3	UNCOLLECTIBLE ACCOUNTS - MERCHANDISE
C-8 p.4	UNCOLLECTIBLE ACCOUNTS - MERCHANDISE (CONT.)
C-8 p.5	UNCOLLECTIBLE ACCOUNTS – MISCELLANEOUS
C-8 p.6	UNCOLLECTIBLE ACCOUNTS - MISCELLANEOUS (CONT.)
C-9 p.1	ADVERTISING EXPENSES
C-9 p.2	ADVERTISING EXPENSES - (CONT.)
C-10 p.1	CIVIC AND CHARITABLE CONTRIBUTIONS
C-11 p.1	INDUSTRY ASSOCIATION DUES

MFR SCHEDULES SPONSORED BY
ROBERT J. CLANCY, JR.

SCHEDULE NO.	TITLE
C-12 p.1	LOBBYING AND POLITICAL EXPENSES
C-13 p.1	RATE CASE EXPENSES
C-14 p.1	MISCELLANEOUS GENERAL EXPENSES
C-15 p.1	OUT OF PERIOD ADJUSTMENTS
C-16 p.1	GAIN/LOSS ON DISPOSITION OF PROPERTY
C-17 p.1	DEPRECIATION EXPENSE
C-18 p.1	AMORTIZATION/RECOVERY SCHEDULE
C-20 p.1	SUMMARY OF TOTAL INCOME TAX PROVISION
C-21 p.1	STATE AND FEDERAL INCOME TAX - CURRENT
C-22 p.1	INTEREST EXPENSE - INCOME TAX
C-23 p.1	BOOK / TAX DIFFERENCES - PERMANENT
C-24 p.1	DEFERRED INCOME TAX EXPENSE
C-25 p.1	DEFERRED INCOME TAX ADJUSTMENT
C-26 p.1	PARENT DEBT INFORMATION
C-27 p.1	INCOME TAX RETURNS
C-28 p.1	MISCELLANEOUS TAX INFORMATION
C-29 p.1	CONSOLIDATED RETURN
C-30 p.1	OTHER TAXES - DETAIL
C-30 p.2	OTHER TAXES - DETAIL - (CONT.)
C-31 p.1	OUTSIDE PROFESSIONAL SERVICES
C-32 p.1	AFFILIATED COMPANY TRANSACTIONS
C-33 p.1	WAGE & SALARY INCREASES COMPARED TO C.P.I.
C-34 p.1	O & M BENCHMARK COMPARISONS
C-35 p.1	O & M ADJUSTMENTS BY FUNCTION
C-36 p.1	BASE YEAR RECOVERABLE O & M EXPENSES BY FUNCTION
C-37 p.1	O & M COMPOUND MULTIPLIER
C-38 p.1	O & M BENCHMARK VARIANCE BY FUNCTION
C-38 p.2	O & M BENCHMARK VARIANCE BY FUNCTION
C-38 p.3	O & M BENCHMARK VARIANCE BY FUNCTION
C-38 p.4	O & M BENCHMARK VARIANCE BY FUNCTION
C-38 p.5	O & M BENCHMARK VARIANCE BY FUNCTION
D-1 p.1	COST OF CAPITAL - 13 MONTH AVERAGE
D-1 p.2	COST OF CAPITAL - HISTORICAL DATA
D-2 p.1	LONG TERM DEBT OUTSTANDING - DETAIL
D-2 p.2	LONG TERM DEBT - CALL PROVISIONS
D-3 p.1	SHORT TERM DEBT
D-4 p.1	PREFERRED STOCK
D-5 p.1	COMMON STOCK ISSUES
D-6 p.1	CUSTOMER DEPOSITS
D-7 p.1	SOURCES AND USES OF FUNDS
D-8 p.1	ISSUANCE OF SECURITIES
D-9 p.1	SUBSIDIARY INVESTMENTS
D-10 p.1	RECONCILIATION OF AVERAGE CAPITAL STRUCTURE TO AVERAGE JURISDICTIONAL RATE BASE
D-11 p.1	FINANCIAL INDICATORS - COVERAGE RATIOS
D-11 p.2	FINANCIAL INDICATORS - PERCENTAGE OF CONSTRUCTION FUNDS INTERNALLY GENERATED
D-11 p.3	FINANCIAL INDICATORS - AFUDC AS A PERCENTAGE OF INCOME
D-12 p.1	APPLICANT'S MARKET DATA

MFR SCHEDULES SPONSORED BY
ROBERT J. CLANCY, JR.

SCHEDULE NO.	TITLE
E-6 p.1	DERIVATION OF RATE BASE
E-6 p.2	DERIVATION OF RATE BASE - (CONT.)
E-6 p.3	DERIVATION OF COST SERVICE
E-6 p.4	DERIVATION OF COST SERVICE - (CONT.)
E-6 p.5	DERIVATION OF COST SERVICE - (CONT.)
F-1 p.1	CALCULATION OF INTERIM RATE RELIEF - RATE OF RETURN
F-2 p.1	WORKING CAPITAL - ASSETS
F-2 p.2	WORKING CAPITAL - LIABILITIES
F-3 p.1	ADJUSTMENTS TO RATE BASE
F-4 p.1	NET OPERATING INCOME
F-5 p.1	ADJUSTMENTS TO NET OPERATING INCOME
F-5 p.2	ADJUSTMENTS TO NET OPERATING INCOME - (CONT.)
F-6 p.1	REVENUE EXPANSION FACTOR
F-7 p.1	REVENUE DEFICIENCY
F-8 p.1	AVERAGE COST OF CAPITAL
F-9 p.1	RECONCILIATION OF RATE BASE TO CAPITAL STRUCTURE (INTERIM)
G-1 p.1	RATE BASE, PROJECTED
G-1 p.2	WORKING CAPITAL, PROJECTED
G-1 p.3	WORKING CAPITAL, PROJECTED
G-1 p.4	RATE BASE ADJUSTMENTS
G-1 p.5	BALANCE SHEET, BASE YR + 1
G-1 p.6	BALANCE SHEET, BASE YR + 1
G-1 p.7	BALANCE SHEET, PROJECTED
G-1 p.8	BALANCE SHEET, PROJECTED
G-1 p.9	PLANT, BASE YEAR + 1
G-1 p.10	PLANT, PROJECTED
G-1 p.11	DEPRECIATION RESERVE, BASE + 1
G-1 p.12	DEPRECIATION RESERVE, PROJECTED
G-1 p.13	AMORTIZATION RESERVE, BASE +1
G-1 p.14	AMORTIZATION RESERVE, PROJECTED
G-2 p.1	NOI SUMMARY, PROJECTED
G-2 p.2	NOI ADJUSTMENTS, PROJECTED
G-2 p.3	NOI ADJUSTMENTS, PROJECTED
G-2 p.4	INCOME STATEMENT, BASE + 1
G-2 p.5	INCOME STATEMENT, PROJECTED
G-2 p.12	PROJECTED O&M EXPENSES - TRENDS
G-2 p.13	PROJECTED O&M EXPENSES - TRENDS
G-2 p.14	PROJECTED O&M EXPENSES - TRENDS
G-2 p.15	PROJECTED O&M EXPENSES - TRENDS
G-2 p.16	PROJECTED O&M EXPENSES - TRENDS
G-2 p.17	PROJECTED O&M EXPENSES - TRENDS
G-2 p.18	PROJECTED O&M EXPENSES - TRENDS
G-2 p.19	PROJECTED O&M EXPENSES - TRENDS
G-2 p.23	DEPRECIATION EXPENSE, BASE + 1
G-2 p.24	AMORTIZATION, BASE + 1
G-2 p.26	DEPRECIATION EXPENSE, PROJECTED
G-2 p.27	AMORTIZATION, PROJECTED

MFR SCHEDULES SPONSORED BY
ROBERT J. CLANCY, JR.

SCHEDULE NO.	TITLE
G-2 p.29	INCOME TAX SUMMARY, BASE + 1
G-2 p.30	INCOME TAX CALC., BASE + 1
G-2 p.31	DEFERRED INCOME TAX EXPENSE, BASE + 1
G-2 p.32	INCOME TAX SUMMARY, PROJECTED
G-2 p.33	INCOME TAX CALCULATION, PROJECTED
G-2 p.34	DEFERRED INCOME TAX EXPENSE, PROJECTED
G-3 p. 1	COST OF CAPITAL, BASE + 1
G-3 p.2	COST OF CAPITAL, PROJECTED
G-3 p.3	LONG TERM DEBT OUTSTANDING, PROJECTED
G-3 p.4	SHORT TERM DEBT OUTSTANDING, PROJECTED
G-3 p.5	PREFERRED STOCK, PROJECTED
G-3 p.6	COMMON STOCK, PROJECTED
G-3 p.7	CUSTOMER DEPOSITS
G-3 p.8	STOCK/BOND ISSUES
G-3 p.9	FINANCIAL INDICATORS, PROJECTED
G-3 p.10	FINANCIAL INDICATORS, PROJECTED
G-3 p.11	FINANCIAL INDICATORS, PROJECTED
G-4 p.1	REVENUE EXPANSION FACTOR
G-5 p.1	REVENUE DEFICIENCY, PROJECTED
G-6 p.1	MAJOR ASSUMPTIONS, PROJECTED
G-6 p.2	MAJOR ASSUMPTIONS, PROJECTED
G-6 p.3	MAJOR ASSUMPTIONS, PROJECTED
G-6 p.4	MAJOR ASSUMPTIONS, PROJECTED
G-6 p.5	MAJOR ASSUMPTIONS, PROJECTED

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: CITY GAS COMPANY OF FLORIDA
A DIVISION OF NUI CORPORATION

DOCKET NO 000768-GU

EXPLANATION: PROVIDE A SCHEDULE CALCULATING A 13-MONTH AVERAGE RATE BASE FOR THE HISTORIC BASE YEAR, THE HISTORIC BASE YEAR PLUS ONE, AND THE PROJECTED TEST YEAR.

TYPE OF DATA SHOWN:
HISTORIC BASE YEAR DATA: 09/30/99
HISTORIC BASE YEAR + 1: 09/30/00
PROJECTED TEST YEAR: 09/30/01
WITNESS: R. CLANCY

		Historical Base Year (1999)			Historical Base Year + 1 (2000)	Projected Test Year (2001)		
Line No.	Description	Average Unadjusted	Company Adjustments	Average Adjusted	Average Unadjusted	Average Unadjusted	Company Adjustments	Average Adjusted
	UTILITY PLANT							
1	GAS PLANT IN SERVICE	$ 143,756,865	$ 3,041,377	$ 146,798,242	$ 156,451,363	$ 169,205,682	$ -	$ 169,205,682
2	COMMON PLANT ALLOCATED	-	665,093	665,093	-	-	555,877	555,877
3	ACQUISITION ADJUSTMENT	30,337,093	(29,188,220)	1,148,873	30,810,354	31,184,548	(29,370,230)	1,814,318
4	CONSTRUCTION WORK IN PROGRESS	5,242,621	(4,093,626)	1,148,995	2,829,654	6,709,934	-	6,709,934
5	TOTAL	179,336,579	(29,575,376)	149,761,203	190,091,371	207,100,164	(28,814,353)	178,285,811
	DEDUCTIONS							
6	ACCUMULATED DEPRECIATION - UTILITY PLANT	58,563,873	(870,236)	57,693,637	63,541,520	67,713,522	-	67,713,522
7	ACCUM. DEPR. - COMMON PLANT ALLOCATED	-	(256,399)	(256,399)	-	-	(5,359)	(5,359)
8	ACCUM. AMORTIZATION - ACQUISITION ADJ'TS	10,573,358	(10,208,116)	365,242	11,595,214	12,629,164	(12,201,852)	427,312
9	TOTAL DEDUCTIONS	69,137,231	(11,334,751)	57,802,480	75,136,734	80,342,686	(12,207,211)	68,135,475
10	UTILITY PLANT, NET	110,199,348	(18,240,625)	91,958,723	114,954,637	126,757,478	(16,607,142)	110,150,336
	ALLOWANCE FOR WORKING CAPITAL							
11	BALANCE SHEET METHOD	(18,208,266)	20,995,036	2,786,770	(21,062,910)	(33,279,225)	37,115,659	3,836,434
12	TOTAL RATE BASE	$ 91,991,082	$ 2,754,411	$ 94,745,493	$ 93,891,727	$ 93,478,253	$ 20,508,517	$ 113,986,770
13	NET OPERATING INCOME	$ 5,254,796	$ 205,925	$ 5,460,721	$ 4,922,383	$ 3,280,858	$ 1,290,301	$ 4,571,159
14	RATE OF RETURN	5.71%		5.76%	5.24%	3.51%		4.01%

EXHIBIT NO.___(RJC-2)
CITY GAS COMPANY OF FLORIDA
DOCKET NO. 000768-GU
PAGE 1 OF 1

SUPPORTING SCHEDULES: B-2 p 1, G-1 pp 2, 4, 5 & 7, G-5 | RECAP SCHEDULES

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: CITY GAS COMPANY OF FLORIDA
A DIVISION OF NUI CORPORATION

DOCKET NO.: 000768-GU

EXPLANATION: PROVIDE THE CALCULATION OF NET OPERATING INCOME PER BOOKS FOR THE HISTORIC BASE YEAR, THE PROJECTED NET OPERATING INCOME FOR THE HISTORIC BASE YEAR + 1, AND THE PROJECTED TEST YEAR.

TYPE OF DATA SHOWN:
HISTORIC BASE YEAR DATA: 09/30/99
HISTORIC BASE YEAR + 1: 09/30/00
PROJECTED TEST YEAR: 09/30/01
WITNESS: R. CLANCY

		Historical Base Year (1999)			Historical Base Year + 1 (2000)	Projected Test Year (2001)		
Line No.	Description	Per Books	Company Adjustments	Adjusted	Per Books	Per Books	Company Adjustments	Adjusted
1	OPERATING REVENUE:							
2	OPERATING REVENUES	78,350,986	(47,349,461)	31,001,525	95,868,874	61,790,681	(30,655,548)	31,135,133
3	REVENUE RELIEF	-	-	-	-	-	-	-
4	CHANGE IN UNBILLED REVENUES	-	-	-	(2,799)	-	-	-
5	REVENUES DUE TO GROWTH	-	-	-	482,548	2,439,504	-	2,439,504
6	TOTAL REVENUES	78,350,986	(47,349,461)	31,001,525	96,348,623	64,230,185	(30,655,548)	33,574,637
7	OPERATING EXPENSES:							
8	COST OF GAS	41,404,438	(41,404,438)	-	53,776,860	25,004,943	(25,004,943)	-
9	OPERATION & MAINTENANCE	21,826,748	(4,546,255)	17,280,493	24,755,781	22,981,629	(3,387,549)	19,594,080
10	CONSERVATION COSTS				2,079,967	2,308,203	(2,308,203)	-
11	DEPRECIATION & AMORTIZATION	5,288,697	524,911	5,813,608	6,082,404	6,622,601	344,687	6,967,288
12	REVENUE RELATED TAXES	-	-	-	2,394,768	2,523,902	(2,523,902)	-
13	TAXES OTHER THAN INCOME	4,596,848	(3,208,794)	1,388,054	2,585,746	2,909,103	(385,800)	2,523,303
14	INCOME TAXES FEDERAL	(700,739)	911,067	210,328	(492,200)	(1,195,200)	1,126,949	(68,251)
15	INCOME TAXES - STATE	(119,952)	155,955	36,003	(92,709)	(204,594)	192,912	(11,682)
16	DEFERRED TAXES - FEDERAL	659,628	-	659,628	252,607	(35,037)	-	(35,037)
17	DEFERRED TAXES - STATE	152,690	-	152,690	83,016	33,777	-	33,777
18	INVESTMENT TAX CREDITS	(12,168)	12,168	-	-	-	-	-
19	TOTAL OPERATING EXPENSES	73,096,190	(47,555,386)	25,540,804	91,426,240	60,949,327	(31,945,849)	29,003,478
20	NET OPERATING INCOME	5,254,796	205,925	5,460,721	4,922,383	3,280,858	1,290,301	4,571,159

SUPPORTING SCHEDULES: C-1, G-2 pp 2-5

RECAP SCHEDULES: G1 p1, A4

EXHIBIT NO. ____ (RJC-3)
CITY GAS COMPANY OF FLORIDA
DOCKET NO. 000768-GU
PAGE 1 OF 1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING A 13 MONTH AVERAGE COST OF CAPITAL FOR THE PROJECTED TEST YEAR

TYPE OF DATA SHOWN:
PROJECTED TEST YEAR: 09/30/01
WITNESS: R. CLANCY

COMPANY: CITY GAS COMPANY OF FLORIDA
A DIVISION OF NUI CORPORATION

DOCKET NO.: 000768-GU

			Adjustments							
Line No.	Description	Per Books	To Conform with Ratio of Investor Sources	Specific	Pro Rata	Adjusted	Ratio	Cost Rate	Weighted Cost	Consolidated Investor Sources
1	COMMON EQUITY	37,348,761	13,649,387	-	(8,913,718)	42,084,430	36.92%	11.70%	4.32%	43.38%
2	LONG TERM DEBT	53,645,942	5,924,882	-	(10,412,094)	49,158,730	43.13%	6.54%	2.82% a	50.67%
3	SHORT TERM DEBT	26,572,040	(19,574,269)	-	(1,223,106)	5,774,665	5.07%	8.00%	0.41% a	5.95%
4	CUSTOMER DEPOSITS	5,596,459	-	-	-	5,596,459	4.91%	6.73%	0.33% a	
5	DEFERRED TAXES	20,221,678	-	(9,732,846)	-	10,488,832	9.20%	0.00%	0.00%	
6	TAX CREDIT	883,654	-	-	-	883,654	0.78%	0.00%	0.00%	
7	TOTAL	144,268,534	-	(9,732,846)	(20,548,918)	113,986,770	100.00%		7.88%	

INTEREST SYNCHRONIZATION CALCULATION			
RATE BASE		$113,986,770	
x WEIGHTED AVERAGE COST OF DEBT	(SUM OF "a")	3.56%	
SYNCHRONIZED INTEREST		4,057,929	
INTEREST PER BOOKS		4,955,250	
INTEREST PER BOOKS OVER SYNCHRONIZED INTEREST CALCULATED		897,321	
STATE TAX @	5.50%	49,353	49,353
		847,968	
FEDERAL TAX @	34.00%		288,309
TOTAL INCOME TAX ADJUSTMENT			$337,662

EXHIBIT NO. ___ (RJC-4)
CITY GAS COMPANY OF FLORIDA
DOCKET NO. 000768-GU
PAGE 1 OF 1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE CALCULATION OF THE REVENUE DEFICIENCY FOR THE PROJECTED TEST YEAR.

TYPE OF DATA SHOWN:
PROJECTED TEST YEAR: 09/30/01
WITNESS: R. CLANCY

COMPANY: CITY GAS COMPANY OF FLORIDA
A DIVISION OF NUI CORP.
DOCKET NC 000768-GU

LINE NO.	DESCRIPTION	AMOUNT
1	ADJUSTED RATE BASE	$ 113,986,770
2	REQUESTED RATE OF RETURN	7.88%
3	N.O.I. REQUIREMENTS	8,982,157
4	LESS: ADJUSTED N.O.I.	4,571,159
5	N.O.I. DEFICIENCY	$ 4,410,998
6	EXPANSION FACTOR	1.6282
7	REVENUE DEFICIENCY	$ 7,181,988

SUPPORTING SCHEDULES: G-1 p 1, G-3 p 2, G-4

RECAP SCHEDULES: A-1

EXHIBIT NO. ____ (RJC-5)
CITY GAS COMPANY OF FLORIDA
DOCKET NO. 000768-GU
PAGE 1 OF 1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Application of City Gas Company of Florida for approval of proposed rates	**) Docket No. 000768-GU**

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON BEHALF OF

CITY GAS COMPANY OF FLORIDA

CITY GAS COMPANY OF FLORIDA

DIRECT TESTIMONY OF DR. ROGER A MORIN

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet where I conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on such topics as "Utility Finance", "Utility Cost of Capital", "Alternative Regulatory Frameworks," and on "Utility Capital Allocation" which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va. 1984. My more recent book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities, was released by the same publisher in late 1994. I have engaged in extensive consulting activities on behalf of numerous corporations and legal firms in matters of financial management and corporate litigation. Exhibit No. ___ (RAM-1) describes my professional credentials in more detail.

Q. HAVE YOU TESTIFIED ON COST OF CAPITAL BEFORE?

A. Yes, I have been a cost of capital witness before more than 40 regulatory boards in North America, including the Florida Public Service Commission ("FPSC" or the "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have appeared before the following state and provincial commissions:

Alabama
Alaska
Alberta
Arizona
British Columbia
California
Colorado
Florida
Georgia
Hawaii
Illinois
Indiana
Iowa
Louisiana
Manitoba
Michigan
Minnesota
Mississippi
Montana
Nevada
New Brunswick
New Jersey
New York
Newfoundland
North Carolina
North Dakota
Ohio
Oklahoma
Ontario
Oregon
Pennsylvania
Quebec
South Carolina
Tennessee
Texas
Utah
Vermont
Washington
West Virginia

The details of my participation in regulatory proceedings are provided in Exhibit ___ (RAM-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to conduct an independent appraisal of the fair and reasonable rate of return on the gas distribution operations of the City Gas Company of Florida ("City Gas" or the "Company"), an operating division of NUI Corporation ("NUI"), with particular emphasis on the fair return on the Company's common equity capital committed to that business; to form an opinion based on my professional judgment as to a return on such capital which will (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain its financial integrity; and (4) be comparable to returns offered on comparable risk investments; and to testify in these proceedings as to that opinion. I have also been asked to comment on the appropriateness of the company's proposed capital structure.

Q. WOULD YOU PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES WHICH ACCOMPANY YOUR TESTIMONY?

A. Yes. I have attached to my testimony Exhibits ___ (RAM-1) through ___ (RAM-7) and Appendix A. These Exhibits and Appendix relate directly to points in my testimony, and are described in further detail in connection with those points.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. I recommend the adoption of a return on overall investment of 7.88% and a rate of return on common equity of 11.7%. In keeping with the Commission's past practices, my recommended return of 11.7% provides the midpoint for an authorized range of 10.7% to 12.7%.

My recommendation is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow (DCF) methodologies. I performed two CAPM analyses, one using the plain vanilla CAPM and another using an empirical approximation of the CAPM (ECAPM). I performed three risk premium analyses: a prospective risk premium analysis on the gas distribution industries, an historical risk premium analysis on the gas distribution industries, and a study of the risk premiums allowed in the gas distribution industries. I also performed DCF analyses on three surrogates for the Company's gas distribution operations. They are: the parent company NUI, a group of gas distribution utilities and a group of generation divested electric utilities. My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses. The overall rate of return on invested capital midpoint implied by my cost of equity recommendation is 7.88%.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized in three (3) broad sections:

I. Regulatory Framework and Rate of Return

II. Cost of Equity Estimates

III. Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF CITY GAS' COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of City Gas' cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers which are comparable to those achieved on alternate competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create an equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES CITY GAS' COST OF CAPITAL RELATE TO THAT OF NUI UTILITIES, INC.?

A. I am treating City Gas as a separate stand-alone entity, distinct from NUI because it is the cost of capital for City Gas that we are attempting to measure and not the cost of capital for NUI Utilities, Inc.'s consolidated overall activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, NUI. The true cost of capital depends on the use to which the capital is put, in this case NUI Utilities' gas operations in Florida. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on City Gas is the return foregone in comparable risk gas operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility division such as City Gas is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. UNDER TRADITIONAL COST OF SERVICE REGULATION PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company covers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of this testimony to estimate a fair and reasonable return on the common equity capital of City Gas.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON EQUITY?

A. As discussed in the next section, the basic premise is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements which are generally determined using market value methods, such as the Risk Premium, CAPM, or the DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk.

Q. HOW IS A UTILITY'S RETURN DERIVED?

A. The required return in dollars is obtained by multiplying the established rate of return set by the regulator by the "rate base". The rate base is essentially the net book value of the utility's plant considered used and useful in dispensing service.

Q. WHAT FUNDAMENTAL PRINCIPLES ARE APPLICABLE IN DETERMINING A RATE OF RETURN THAT IS FAIR AND REASONABLE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases which define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

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

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs". The Court stated:

> *"From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."* (emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."

Therefore, the "end result" of this Commission's decision should be to allow City Gas to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in City Gas' financial integrity, and (3) sufficient to maintain City Gas' creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called "cost of capital". The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by City Gas. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total which each class of capital represents.

While utilities like City Gas enjoy varying (and declining) degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the concept of opportunity costs. When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk. Investors are willing to incur this double penalty only if they are adequately compensated. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES CITY GAS OBTAIN ITS CAPITAL?

A. The funds employed by City Gas will be obtained from NUI Utilities, Inc. in two general forms, debt capital and common equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. The return on common equity estimate can then be easily combined with the embedded cost of debt together with the capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors determine the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the firm, recognizing the opportunity cost of foregone investments in other firms, and the returns available from other investments of comparable risk.

II. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RETURN ON EQUITY FOR CITY GAS?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methods and are designed to estimate the return required by investors on equity capital committed to City Gas.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

A. RISK PREMIUM ESTIMATES

Q. PLEASE DESCRIBE THE RISK PREMIUM METHOD FOR DETERMINING THE COST OF COMMON EQUITY.

A. The Risk Premium method of determining the cost of equity recognizes the fundamental principle that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward. First, determine the historical spread between the return on debt and the return on equity. Second, this spread must be added to the current debt yield to derive an estimate of current equity return requirements.

The magnitude of the relative risk premiums is determined by shifts in demand and supply in each capital market segment, which are in turn driven by investors' attitudes towards risk, and by the relative risk differentials perceived by investors between each type of security.

The risk premium approach to estimating the cost of equity derives its merits and its usefulness from the simple fact that while equity returns cannot be readily quantified at a given point in time, the returns on bonds can be assessed on a regular basis. If the magnitude of the risk premium between stocks and bonds is known, then this information can be utilized to determine the cost of common equity.

Q. HOW DID YOU APPLY THE RISK PREMIUM METHOD TO CITY GAS?

A. In order to quantify the risk premium for City Gas, I have performed five risk premium studies. The first two CAPM-driven studies deal with aggregate stock market risk premium evidence and the other three empirical studies deal directly with the gas distribution utility industry.

1. CAPM ESTIMATES

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. I developed two risk premium estimates based respectively on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 6.0%. For beta, I used 0.66, and for the market risk premium, I used 6.9%. These inputs to the CAPM are explained below.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSES?

A. To implement the Risk Premium method, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on long-term Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity, rather than short-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are also used by foreign governments, firms, and individuals as a temporary safe-house for money. Short-term rates are largely administered rates.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

The level of U.S. Treasury long-term bond yields prevailing in July 2000 was 6.0%.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement of the rates of return to a stock with those of the market as a whole. Therefore, it indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market. The beta coefficient thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return which cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

Of course, the Company is not publicly traded, and therefore, proxies must be used. It is reasonable to postulate that the Company possesses an investment risk profile similar to publicly-traded natural gas distribution utility business. As a proxy for the Company's beta, I have therefore examined the betas of natural gas distribution utilities contained in Moody's Natural Gas Distribution Utilities Index. The group is shown in Exhibit ___ (RAM-4). The average beta for the group is 0.66. I also note that the Company's parent, NUI, has a beta of 0.70.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 6.9%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. Two studies guided the assumed range. First, the Ibbotson

Associates study of historical returns from 1926 to 1999 shows that a broad market sample of common stocks outperformed long-term Treasury bonds by 7.8%. Second, a DCF analysis applied to the aggregate equity market indicates a prospective market risk premium of 6.0%. The average of the two estimates is 6.9%.

Q. WHY DID YOU USE LONG HISTORICAL TIME PERIODS IN ARRIVING AT YOUR MARKET RISK PREMIUM ESTIMATE?

A. It is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. This is because realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. For my second estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's "Value Line Investment Survey for Windows 95" ("VLIS") software. Excluding high-growth stocks, the dividend yield on the aggregate market is currently 2.7% (VLIS 07/2000 edition) on dividend-paying stocks, and the projected growth for the Value Line common stocks is in the range of 6.7% to 11.0%. Adding the two components together produces an expected return on the aggregate equity market in the range of 9.4% to 13.7%, with a midpoint of 11.6%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 11.8%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to 12.0%. The implied risk premium is therefore 6.0% over long-term U.S. Treasury bonds which are yielding 6.0%.

The average market risk premium result from the historical and prospective studies is 6.9%, which is my estimate of the market risk premium.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 6.0%, a beta of 0.66, and a market risk premium of 6.9%, the CAPM estimate of City Gas' return on equity is: 6.0% + 0.66 x 6.9% = 10.6%. This estimate becomes 10.9% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. These expanded CAPMs typically produce a risk-return relationship that is "flatter" than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 6.0% for R_F, a market risk premium of 6.9% for R_M - R_F and a beta of 0.66 in the above equation, the return on common equity is 11.1% without flotation cost and 11.4% with flotation costs.

2. <u>PROSPECTIVE RISK PREMIUM ESTIMATES</u>

Q. PLEASE DESCRIBE YOUR PROSPECTIVE RISK PREMIUM ANALYSIS FOR THE GAS DISTRIBUTION UTILITY INDUSTRY.

A. I estimated a risk premium for the gas distribution industry using a month-to-month time series analysis performed on Moody's Gas Distribution Utility Index over the past fifteen years when the required data first became available. The reason for performing the risk premium study on an industry composite rather than on individual company data is to mitigate the possible vagaries of individual company results.

The analysis is depicted in Exhibit ___ (RAM-2). The risk premium is estimated by computing the cost of equity capital for each month from 1984 to 1999 using the DCF model, and then subtracting the yield on long-term Treasury bonds for that month. The spot dividend yield on Moody's Gas Distribution Utility Common Stocks Index is converted into an expected dividend yield, and the expected growth was the average on Moody's Gas

Distribution Utilities of the analysts' consensus forecast reported in IBES for that month. The average risk premium over Treasury bonds for the average gas distributor was 4.2%, adjusted for flotation cost. Given that 30-year Treasury bonds are currently yielding 6.0%, the implied cost of equity for the average gas distribution utility from this particular method is 6.0% + 4.2% = 10.2%.

3. HISTORICAL RISK PREMIUM ESTIMATES

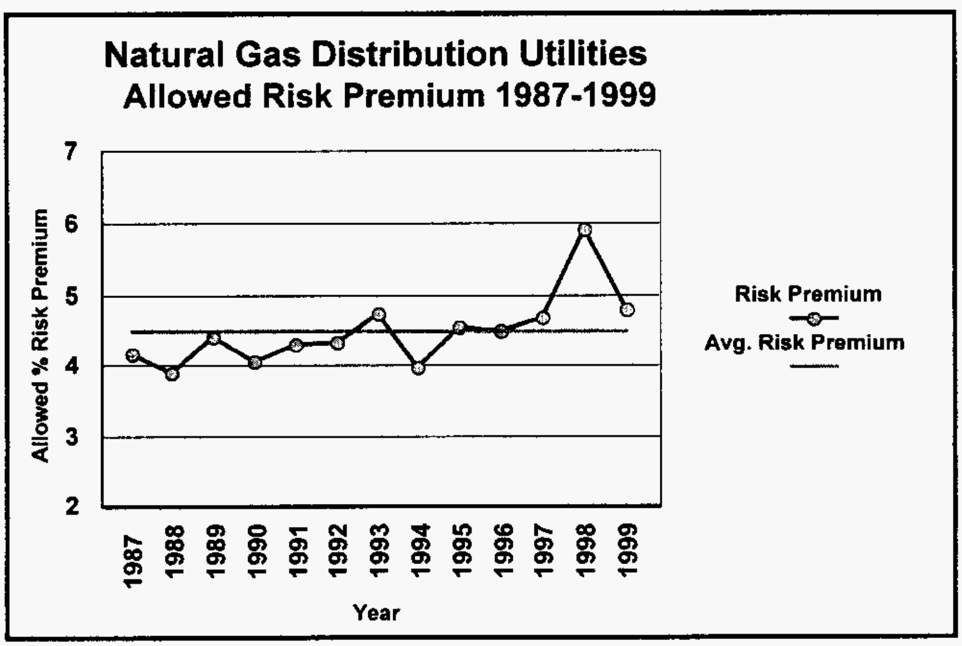
Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION INDUSTRY.

A. I also examined historical risk premiums, in contrast to the previous risk premium test which studied prospective risk premiums. A historical risk premium for the natural gas distribution utility industry was estimated with an annual time series analysis from 1955 to 1999 applied on the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable prior to 1955. The analysis is depicted on Exhibit ___ (RAM-3). The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 1999 using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The average risk premium over the period was 5.8% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 6.0%, the implied cost of equity for the average gas distribution utility from this particular method is 6.0% + 5.8% = 11.8%.

4. ALLOWED RISK PREMIUM

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE GAS DISTRIBUTION UTILITY INDUSTRY.

A. To estimate City Gas' cost of common equity, I examined the historical risk premiums implied in the ROEs allowed by regulatory commissions in hundreds of natural gas utility ROE decisions over the period 1987-1999 relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term Treasury yields was 4.5% for the 1987-1999 period as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. The rising trend of the risk premium in response to rising competition and restructuring is noteworthy.

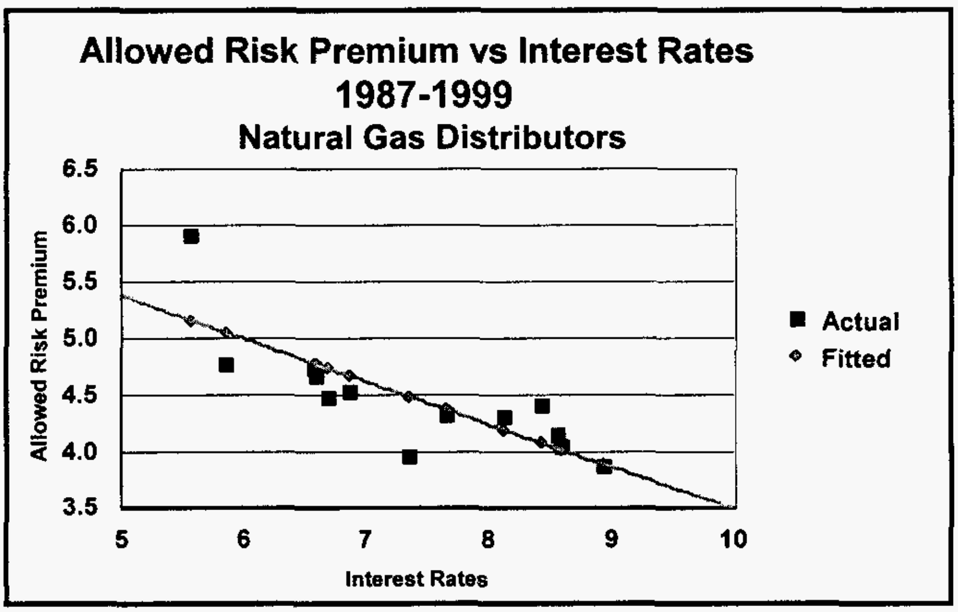


A more careful review of these ROE decisions relative to interest rate trends also reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1987-1999 period:

$$RP = 0.0727 - 0.380\ YIELD \qquad R^2 = 0.64$$

(t=4.44)

The relationship is statistically significant as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows the inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 6.0% in the above equation suggests a risk premium estimate of 5.0% that would be allowed. This in turn implies an allowed ROE of 11.0%.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the various risk premium studies:

RISK PREMIUM STUDY	ROE
CAPM	10.9%
ECAPM	11.4%
Prospective Gas Distribution	10.2%
Historical Natural Gas Distribution	11.8%
Allowed Risk Premium Natural Gas Utilities	11.0%

B. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_o = current stock price

g = expected growth rate of future dividends

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known. The assumptions are discussed in detail in Chapter 4 of my book, Regulatory Finance. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid annually when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE CITY GAS' COST OF EQUITY WITH THE

DCF MODEL?

A. I applied the DCF model to three proxy groups for City Gas: a group consisting of the gas distribution companies that make up Moody's Natural Gas Distribution Utility Index, City Gas' parent company, NUI, and a group consisting of electric utilities that are predominantly involved in the energy distribution business. I refer to the latter as "generation divestiture electric utilities."

To apply the DCF model, two components are required: the expected dividend yield (D_1/P_o) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the spot dividend yields reported in the July 2000 edition of VLIS. The vagaries of individual company stock prices are attenuated when using a large group of companies.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate which investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed. There are two potential proxies. The first proxy for expected growth is historical growth.

Q. PLEASE DISCUSS THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO GAS DISTRIBUTION UTILITIES.

A. Under normal circumstances of stability, it is reasonable to assume that historical growth rates in dividends/earnings influence investors' assessment of the long-run growth rate of future dividends/earnings.

The historical growth in earnings, dividends, and book value per share over the last five years for the gas distribution utilities that make up Moody's Gas Distribution Utility Index are 2.7%, 2.6%, and 4.8%, respectively, as published in the current edition of VLIS. These historical growth rates have questionable relevance as proxies for future long-term growth. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the energy utility industry from a regulated monopoly to a competitive environment.

These anemic historical growth rates are certainly not representative of these companies' normalized long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 2.7%, 2.8%, and 4.8% to the average expected dividend yield of 5.3% shown on Column 4 of Exhibit ___ (RAM-4) produces unreasonable cost of equity estimates of 8.0%, 8.1%, and 10.1%, using earnings, dividends, and book value growth rates, respectively. Two of the three estimates of equity costs are less than the companies' bond yield.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING ANALYSTS' GROWTH FORECASTS FOR THE GAS DISTRIBUTION UTILITY INDUSTRY?

A. As a second proxy for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated in Institutional Brokers' Estimate System's ("IBES") monthly publications. I have used analysts' long-term growth forecasts contained in IBES as proxies for investors' growth expectations in applying the DCF model. I have also used Value Line's growth forecast as an additional proxy.

As shown on Column 3 of page 1 of Exhibit ___ (RAM-4), the average long-term growth forecast obtained from the IBES corporate earnings data base is 6.9% for Moody's Natural Gas Utilities. Adding this growth rate to the average expected dividend yield of 5.3% shown in Column 4 produces an estimate of equity costs of 12.2% for the gas distribution group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 5 brings the cost of equity estimate to 12.5%, shown in Column 6.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 6.3% instead of the IBES consensus growth forecast, the cost of equity for Moody's Natural Gas Utilities is 13.4%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 13.6%. Removing the outlying high estimate of 21.7% from Equitable Resources, the cost of equity estimate is 12.0% unadjusted for flotation costs, and 12.3% with allowance for flotation costs. This analysis is displayed on page 2 of Exhibit ___(RAM-4).

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE GENERATION DIVESTITURE ELECTRIC UTILITIES?

A. Exhibit ___(RAM-5) displays a group of 13 electric utilities labeled "Generation Divestiture Electric Utilities" by Moody's. These are publicly-listed parent companies whose electric utility operating subsidiaries have divested generation assets or are in the process of doing so and are therefore reasonable proxies for the gas distribution business. It is reasonable to postulate that the Company's natural gas distribution business possesses an investment risk profile similar to today's electricity distribution business. These electric "wires" companies possess economic characteristics similar to those of natural gas distribution utilities. They are both involved in the distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital intensive network with similar physical characteristics. They are both regulated by public utility regulators.

As shown on Column 2 of page 1 of Exhibit ___ (RAM-5), the average long-term growth forecast obtained from IBES is 6.1% for this group. Adding this growth rate to the average expected dividend yield of 6.0% shown in Column 3 produces an estimate of equity costs of 12.1% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 12.4%, shown in Column 5.

Using Value Line's long-term earnings growth forecast of 5.9% instead of the IBES consensus forecast, the cost of equity for the generation divestiture electrics is 12.8%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 13.1%. This analysis is displayed on page 2 of Exhibit ___(RAM-5).

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR CITY GAS' PARENT COMPANY, NUI?

A. As shown on Column 3 of page 1 of Exhibit ___ (RAM-6), the long-term growth forecast obtained from IBES is 13.2% for NUI. Adding this growth rate to the expected dividend yield of 4.2% shown in Column 4 produces an estimate of equity costs of 17.4% for NUI, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 5 brings the cost of equity estimate to 17.6%, shown in Column 6.

Using Value Line's long-term earnings growth forecast of 14.5% instead of the IBES consensus forecast, the cost of equity is 18.7%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 18.9%. This analysis is displayed on page 2 of Exhibit ___ (RAM-6).

I have given no weight to those results, as the underlying growth rate forecasts are likely due to the growth prospects of NUI's unregulated businesses rather than the regulated component.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for City Gas:

DCF STUDY	ROE
Natural Gas IBES Growth	12.5%
Natural Gas Value Line Growth	12.3%
Gen. Divested Electrics IBES Growth	12.4%
Gen. Divested Electrics Value Line Growth	13.1%

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates (CAPM, Risk Premium, DCF) reported above include an adjustment for flotation cost. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred, they are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is routinely done for bond and preferred stock issues by most regulatory commissions. Clearly, the common equity capital accumulated by the Company through its parent NUI was not cost-free. The flotation cost allowance to the cost of common equity capital is regularly discussed and applied in most corporate finance textbooks.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure".

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs are not expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix A to my testimony discusses flotation costs in detail, and shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated, and 3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock which has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix A, total flotation costs amount to 5% of gross proceeds. This in turn amounts to approximately 30 basis points. That is, dividing the average expected dividend yield of 6.0% for electric utility stocks by 0.95 yields 6.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor which reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the company.

III. SUMMARY & RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed five risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other three risk premium analyses were performed on prospective, historical, and allowed risk premium data from the natural gas distribution industry aggregate data. I also performed DCF analyses on three surrogates for City Gas' gas distribution business: a group consisting of the natural gas distribution utilities that make up Moody's Natural Gas Distribution Utility Index, a group of generation divestiture electric utilities, and City Gas' parent company, NUI. The results are summarized in the table below:

STUDY	COST OF EQUITY
CAPM	10.9%
ECAPM	11.4%
Risk Premium Prospective Gas Distribution	10.2%
Risk Premium Historical Gas Distribution	11.8%
Risk Premium Allowed Gas Distribution	11.0%
DCF Gas Distribution Consensus Growth	12.5%
DCF Gas Distribution Value Line Growth	12.3%
DCF Gen. Divest. Electrics Consensus Growth	12.4%
DCF Generation Divestiture Electrics Value Line Growth	13.1%

The results range from a low of 10.2% to a high of 13.1%, with a midpoint of 11.7%. The average result from the various methodologies is also 11.7%. The truncated mean, obtained by removing the high and low estimates from the computation of the average is 11.8%. The median result is also equal to 11.8%.

Q. WHAT RATE OF RETURN RANGE DO YOU RECOMMEND AS CITY GAS' COST OF EQUITY?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of City Gas' gas distribution operations in the state of Florida at this time is 11.7%. In keeping with the Commission's past practices, my recommended return of 11.7% provides the midpoint for an authorized range of 10.7% to 12.7%.

Q. DOES YOUR RECOMMENDATION ACCOUNT FOR THE COMPANY'S RELATIVELY SMALL SIZE?

A. No, it does not. Although a slightly higher return is warranted for City Gas in view of its relatively small size, this risk is largely offset by the favorable regulatory environment under which the company operates.

Q. IF INTEREST RATES OR RISK PREMIUMS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. WHAT CAPITAL STRUCTURE DO YOU ADOPT FOR PURPOSES OF CALCULATING A WEIGHTED AVERAGE COST OF CAPITAL?

A. City Gas does not have a stand-alone capital structure scrutinized by investors. Following the corporate restructuring of NUI Corporation during fiscal year 2001, City Gas will emerge as a division of a new NUI Utilities, Inc. ("NUI Utilities"), which in turn will be a subsidiary of NUI Corporation. NUI Utilities will contain all the regulated operations of NUI Corporation.

As shown on Exhibit RAM-7, I have adopted NUI Utilities' average capital structure for the projected test year, as supplied to me by the Company. The rationale for using NUI Utilities' capital structure as a proxy for City Gas is that all the equity funds employed by City Gas will be raised by NUI Utilities. It is NUI Utilities' capital structure which will be scrutinized and evaluated by investors. The terms and conditions under which City Gas' funds are raised will be determined by NUI Utilities' capital structure. Moreover, City Gas' ratepayers will enjoy the benefits of NUI Utilities' financial strength and lower cost of capital compared to what City Gas' financial strength and cost of capital would be on a stand-alone basis. Given its small size, City Gas would not enjoy the same creditworthiness and financial solidity as NUI Utilities.

Q. WHAT IS THE OVERALL WEIGHTED AVERAGE COST OF CAPITAL THAT RESULTS FROM INCORPORATION OF YOUR RECOMMENDED 11.7% COST OF COMMON EQUITY RECOMMENDATION?

A. Taking capitalization proportions and embedded costs of debt as supplied to me by the company at my request, combining them with the costs of various forms of financing employed by the company, and combining them with a cost of common equity of 11.7%, the weighted average total cost is 7.88%. This calculation appears on Page 1 of Exhibit ____(RAM-7).

I have examined NUI Utilities' capital structure relative to that of other LDC's. Page 2 of Exhibit ____(RAM-7) shows the company's projected composition of various investor-supplied capital sources, including short-term debt. Page 3 displays the same information without the inclusion of short-term debt. Its common equity ratio of about 46% exclusive of short-term debt is lower than the LDC industry average of 53%.

Q. DO BOND RATING AGENCIES PROVIDE GUIDANCE AS TO AN APPROPRIATE CAPITAL STRUCTURE?

A. Yes, they do. A target capital structure consisting of 50% debt and 50% common equity would place NUI Utilities closer to the guidelines stipulated by bond rating agencies for an A-rating status, which I consider optimal for both the company's investors and its ratepayers. The debt ratio is one of the prime determinants of investment quality scrutinized by bond rating agencies in assigning bond ratings, along with coverage ratios. Standard & Poor's recently revised benchmarks for investor-owned electric and gas distribution utilities with a favorable "Business Position" of 2 on the risk spectrum such as other gas distribution utilities comparable to NUI Utilities, include a total debt ratio in the range of 51.0% - 56.5% for an A rating, and 56.5% - 63.5% for a BBB rating. The midpoint of the required debt ratio is 53.3% for an A rating and 60.0% for a BBB rating. NUI Utilities' total debt ratio of almost 57% places the company technically outside the requirements for an A rating.

Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes, it does.

APPENDIX A

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. Adding the two effects, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock which has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations which show that even if a utility does not contemplate any further common stock offerings, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

which is the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving my DCF estimates of fair return on equity, it was therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 6-8 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 6-8 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 6. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 which will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 7, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 is simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 8. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

RESUME OF ROGER A. MORIN

(Summer 2000)

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EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, Philadelphia, PA., 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2000
  - Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2000
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H.., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates., Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

CORPORATE CONSULTING CLIENTS

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

American Water Works Company

Ameritech

Baltimore Gas & Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central South West Corp.

Cincinnatti Gas & Electric

Cinergy Corp

CORPORATE CONSULTING CLIENTS (CONT'D)

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Constellation Energy

Deerpath Group

Edison International

Edmonton Power Company

Engraph Corporation

Entergy Corp.

Entergy Gulf States Utilities, Inc.

Entergy Louisiana, Inc.

Florida Water Association

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California

GTE Northwest Inc

GTE Service Corp.

GTE Southwest Incorporated

Gulf Power Company

Havasu Water Inc.

Hope Gas Inc.

CORPORATE CONSULTING CLIENTS (CONT'D)

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Mountain Bell

Newfoundland Light & Power - Fortis Inc.

NewTel Enterprises Ltd.

New York Telephone Co.

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Board of Utilities

NUI Corp

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

CORPORATE CONSULTING CLIENTS (CONT'D)

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Price Waterhouse

PSI Energy

Public Service Elec & Gas

Quebec Telephone

Rochester Telephone

SaskPower

Sierra Pacific Resources

Southern Bell

Southern States Utilities

South Central Bell

Sun City Water Company

The Southern Company

Touche Ross and Company

Trans-Quebec & Maritimes Pipeline

US WEST Communications

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty, 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78

- Financial Research Foundation, bi-annual seminar, 1975-79

- Advanced Management Research (AMR), faculty member, 1977-80

- Financial Analysts Federation, Educational chapter:
  "Financial Futures Contracts" seminar

- The Management Exchange Inc., faculty member, 1981-2000.

  NATIONAL SEMINARS:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Phase-in Plans

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Publicly-owned Municipals

Telecommunications, CATV, Energy, Pipeline, Water

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

REGULATORY BODIES:

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Public Service Commission

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television and Telecomm. Commission

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Service Commission

Michigan Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Enérgy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, I989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

- Bell Canada 1994-1995
- PSI Energy 1993, 1994, 1995, 1999
- Cincinnati Gas & Electric 1994, 1996, 1999
- Southern States Utilities, 1995
- CILCO 1995, 1999
- Commonwealth Telephone 1996
- Edison International 1996-8
- Citizens Utilities 1997
- Stentor Companies 1997
- Hydro-Quebec 1998
- Entergy Gulf States Louisiana 1998
- Detroit Edison, 1999
- Entergy Gulf States, Texas, 2000

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences,1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2000
- Financial Management Association, 1978-2000

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multiperiod Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation
"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital, " Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, (New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994

Driving Shareholder Value, McGraw-Hill, forthcoming, July 2000

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980, (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

An Economic & Financial Profile of the Canadian Cablevision Industry. Canadian Radio-Television & Telecomm. Commission (CRTC), 1978

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities, Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications
"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981

"Firm Size and Beta Stability", Georgia State University College of Business, 1982

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2000
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000
- University Senate Committee on Commencement
- University Senate Committee on Information Technology
- University Senate Committee on Student Discipline

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Jan-84	9.50%	10.25%	7.88%	18.12%	18.66%	11.75%	6.91%
Feb-84	10.06%	10.81%	7.50%	18.31%	18.88%	11.95%	6.93%
Mar-84	10.00%	10.75%	7.50%	18.25%	18.82%	12.38%	6.44%
Apr-84	9.72%	10.46%	7.63%	18.09%	18.64%	12.65%	5.99%
May-84	9.76%	10.50%	7.63%	18.13%	18.68%	13.43%	5.25%
Jun-84	9.97%	10.71%	7.38%	18.08%	18.64%	13.44%	5.20%
Jul-84	10.07%	10.85%	7.75%	18.60%	19.17%	13.21%	5.96%
Aug-84	9.30%	10.04%	8.00%	18.04%	18.57%	12.54%	6.03%
Sep-84	9.17%	9.90%	8.00%	17.90%	18.42%	12.29%	6.13%
Oct-84	8.76%	9.46%	8.00%	17.46%	17.96%	11.98%	5.98%
Nov-84	8.78%	9.53%	8.50%	18.03%	18.53%	11.56%	6.97%
Dec-84	8.44%	9.16%	8.50%	17.66%	18.14%	11.52%	6.62%
Jan-85	8.30%	9.01%	8.50%	17.51%	17.98%	11.45%	6.53%
Feb-85	8.32%	9.00%	8.13%	17.12%	17.59%	11.47%	6.12%
Mar-85	7.95%	8.57%	7.75%	16.32%	16.77%	11.81%	4.96%
Apr-85	7.99%	8.61%	7.75%	16.36%	16.81%	11.47%	5.34%
May-85	7.64%	8.20%	7.38%	15.58%	16.01%	11.05%	4.96%
Jun-85	7.39%	7.93%	7.25%	15.18%	15.59%	10.45%	5.14%
Jul-85	7.81%	8.43%	7.88%	16.30%	16.74%	10.50%	6.24%
Aug-85	8.02%	8.63%	7.63%	16.26%	16.71%	10.56%	6.15%
Sep-85	8.19%	8.82%	7.75%	16.57%	17.04%	10.61%	6.43%
Oct-85	8.17%	8.81%	7.88%	16.69%	17.15%	10.50%	6.65%
Nov-85	7.91%	8.53%	7.88%	16.41%	16.86%	10.06%	6.80%
Dec-85	8.12%	8.76%	7.88%	16.63%	17.10%	9.54%	7.56%
Jan-86	7.98%	8.54%	7.00%	15.54%	15.99%	9.40%	6.59%
Feb-86	7.75%	8.27%	6.75%	15.02%	15.46%	8.93%	6.53%
Mar-86	6.35%	6.75%	6.25%	13.00%	13.35%	7.96%	5.39%
Apr-86	6.08%	6.45%	6.13%	12.58%	12.92%	7.39%	5.53%
May-86	6.02%	6.39%	6.13%	12.51%	12.85%	7.52%	5.33%
Jun-86	5.84%	6.22%	6.50%	12.72%	13.05%	7.57%	5.48%
Jul-86	5.86%	6.20%	5.75%	11.95%	12.27%	7.27%	5.00%
Aug-86	5.65%	5.97%	5.75%	11.72%	12.04%	7.33%	4.71%
Sep-86	6.46%	6.80%	5.25%	12.05%	12.41%	7.62%	4.79%
Oct-86	5.99%	6.30%	5.13%	11.42%	11.75%	7.70%	4.05%
Nov-86	6.09%	6.42%	5.38%	11.79%	12.13%	7.52%	4.61%

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Dec-86	6.28%	6.63%	5.50%	12.13%	12.47%	7.37%	5.10%
Jan-87	5.97%	6.29%	5.38%	11.67%	12.00%	7.39%	4.61%
Feb-87	6.04%	6.35%	5.13%	11.47%	11.81%	7.54%	4.27%
Mar-87	6.05%	6.36%	5.13%	11.49%	11.82%	7.55%	4.27%
Apr-87	6.63%	6.94%	4.63%	11.56%	11.93%	8.25%	3.68%
May-87	6.90%	7.22%	4.63%	11.84%	12.22%	8.78%	3.44%
Jun-87	6.47%	6.77%	4.63%	11.39%	11.75%	8.57%	3.18%
Jul-87	6.71%	7.11%	6.00%	13.11%	13.49%	8.64%	4.85%
Aug-87	6.48%	6.87%	6.00%	12.87%	13.23%	8.97%	4.26%
Sep-87	6.80%	7.19%	5.67%	12.85%	13.23%	9.59%	3.64%
Oct-87	7.49%	7.90%	5.50%	13.40%	13.82%	9.61%	4.21%
Nov-87	7.60%	8.02%	5.50%	13.52%	13.94%	8.95%	4.99%
Dec-87	7.79%	8.22%	5.50%	13.72%	14.15%	9.12%	5.03%
Jan-88	7.15%	7.51%	5.00%	12.51%	12.90%	8.83%	4.07%
Feb-88	7.02%	7.39%	5.33%	12.73%	13.12%	8.43%	4.69%
Mar-88	7.28%	7.67%	5.33%	13.00%	13.41%	8.63%	4.78%
Apr-88	7.23%	7.62%	5.33%	12.95%	13.35%	8.95%	4.40%
May-88	7.14%	7.56%	5.83%	13.39%	13.79%	9.23%	4.56%
Jun-88	6.84%	7.24%	5.86%	13.10%	13.48%	9.00%	4.48%
Jul-88	6.88%	7.27%	5.71%	12.99%	13.37%	9.14%	4.23%
Aug-88	7.30%	7.74%	6.00%	13.74%	14.15%	9.32%	4.83%
Sep-88	6.99%	7.43%	6.29%	13.72%	14.11%	9.06%	5.05%
Oct-88	7.09%	7.52%	6.13%	13.65%	14.05%	8.89%	5.16%
Nov-88	7.07%	7.50%	6.13%	13.63%	14.02%	9.02%	5.00%
Dec-88	7.22%	7.66%	6.13%	13.79%	14.19%	9.01%	5.18%
Jan-89	7.12%	7.56%	6.13%	13.68%	14.08%	8.93%	5.15%
Feb-89	7.31%	7.76%	6.13%	13.88%	14.29%	9.01%	5.28%
Mar-89	7.09%	7.51%	5.88%	13.38%	13.78%	9.17%	4.61%
Apr-89	6.74%	7.14%	5.88%	13.01%	13.39%	9.03%	4.36%
May-89	6.65%	7.00%	5.29%	12.29%	12.66%	8.83%	3.83%
Jun-89	6.44%	6.78%	5.29%	12.07%	12.42%	8.27%	4.15%
Jul-89	6.19%	6.46%	4.43%	10.89%	11.23%	8.08%	3.15%
Aug-89	6.17%	6.47%	4.86%	11.33%	11.67%	8.12%	3.55%
Sep-89	6.07%	6.36%	4.86%	11.22%	11.56%	8.15%	3.41%
Oct-89	6.10%	6.41%	5.14%	11.56%	11.89%	8.00%	3.89%

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Nov-89	5.85%	6.14%	4.88%	11.01%	11.33%	7.90%	3.43%
Dec-89	5.63%	5.92%	5.13%	11.04%	11.36%	7.90%	3.46%
Jan-90	6.06%	6.37%	5.13%	11.50%	11.83%	8.26%	3.57%
Feb-90	6.11%	6.43%	5.29%	11.72%	12.06%	8.50%	3.56%
Mar-90	6.21%	6.54%	5.29%	11.82%	12.17%	8.56%	3.61%
Apr-90	6.41%	6.79%	5.86%	12.64%	13.00%	8.76%	4.24%
May-90	6.29%	6.62%	5.29%	11.91%	12.26%	8.73%	3.53%
Jun-90	6.24%	6.57%	5.29%	11.86%	12.20%	8.46%	3.74%
Jul-90	6.49%	6.84%	5.43%	12.27%	12.63%	8.50%	4.13%
Aug-90	6.66%	7.01%	5.29%	12.30%	12.67%	8.86%	3.81%
Sep-90	6.36%	6.73%	5.75%	12.48%	12.83%	9.03%	3.80%
Oct-90	6.23%	6.59%	5.75%	12.34%	12.68%	8.86%	3.82%
Nov-90	6.22%	6.58%	5.71%	12.29%	12.64%	8.54%	4.10%
Dec-90	6.28%	6.58%	4.83%	11.42%	11.76%	8.24%	3.52%
Jan-91	6.40%	6.72%	5.00%	11.72%	12.07%	8.27%	3.80%
Feb-91	6.37%	6.69%	5.00%	11.69%	12.04%	8.03%	4.01%
Mar-91	6.30%	6.62%	5.00%	11.62%	11.96%	8.29%	3.67%
Apr-91	6.19%	6.51%	5.17%	11.68%	12.02%	8.21%	3.81%
May-91	6.04%	6.36%	5.33%	11.70%	12.03%	8.27%	3.76%
Jun-91	6.25%	6.56%	5.00%	11.56%	11.91%	8.47%	3.44%
Jul-91	5.97%	6.27%	5.00%	11.27%	11.60%	8.45%	3.15%
Aug-91	5.92%	6.22%	5.00%	11.22%	11.54%	8.14%	3.40%
Sep-91	5.70%	5.99%	5.00%	10.99%	11.30%	7.95%	3.35%
Oct-91	5.63%	5.92%	5.17%	11.09%	11.40%	7.93%	3.47%
Nov-91	5.58%	5.87%	5.17%	11.04%	11.35%	7.92%	3.43%
Dec-91	5.62%	5.91%	5.17%	11.08%	11.39%	7.70%	3.69%
Jan-92	5.60%	5.89%	5.17%	11.06%	11.37%	7.58%	3.79%
Feb-92	5.71%	6.00%	5.00%	11.00%	11.31%	7.85%	3.46%
Mar-92	5.93%	6.23%	5.00%	11.23%	11.55%	7.97%	3.58%
Apr-92	5.93%	6.23%	5.00%	11.23%	11.55%	7.96%	3.59%
May-92	5.66%	5.94%	5.00%	10.94%	11.26%	7.89%	3.37%
Jun-92	5.48%	5.75%	5.00%	10.75%	11.06%	7.84%	3.22%
Jul-92	5.17%	5.44%	5.17%	10.61%	10.89%	7.60%	3.29%
Aug-92	5.10%	5.36%	5.17%	10.53%	10.82%	7.39%	3.43%
Sep-92	5.02%	5.28%	5.17%	10.45%	10.73%	7.34%	3.39%

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Oct-92	5.19%	5.46%	5.17%	10.63%	10.92%	7.53%	3.39%
Nov-92	5.23%	5.52%	5.50%	11.02%	11.31%	7.61%	3.70%
Dec-92	5.14%	5.42%	5.50%	10.92%	11.21%	7.44%	3.77%
Jan-93	5.05%	5.34%	5.83%	11.17%	11.46%	7.34%	4.12%
Feb-93	4.78%	5.05%	5.67%	10.72%	10.99%	7.09%	3.90%
Mar-93	4.64%	4.91%	5.83%	10.74%	11.00%	6.82%	4.18%
Apr-93	4.83%	5.11%	5.83%	10.94%	11.21%	6.85%	4.36%
May-93	4.80%	5.07%	5.67%	10.74%	11.01%	6.92%	4.09%
Jun-93	4.66%	4.92%	5.67%	10.59%	10.85%	6.81%	4.04%
Jul-93	4.52%	4.77%	5.50%	10.27%	10.52%	6.63%	3.89%
Aug-93	4.54%	4.79%	5.50%	10.29%	10.54%	6.32%	4.22%
Sep-93	4.62%	4.87%	5.50%	10.37%	10.63%	6.00%	4.63%
Oct-93	4.64%	4.89%	5.33%	10.22%	10.47%	5.94%	4.53%
Nov-93	4.85%	5.11%	5.33%	10.44%	10.71%	6.21%	4.50%
Dec-93	4.74%	4.95%	4.50%	9.45%	9.71%	6.25%	3.46%
Jan-94	4.74%	4.95%	4.50%	9.45%	9.71%	6.29%	3.42%
Feb-94	4.97%	5.19%	4.50%	9.69%	9.97%	6.49%	3.48%
Mar-94	5.03%	5.26%	4.67%	9.93%	10.21%	6.91%	3.30%
Apr-94	5.14%	5.37%	4.50%	9.87%	10.15%	7.27%	2.88%
May-94	5.36%	5.63%	5.00%	10.63%	10.92%	7.41%	3.51%
Jun-94	5.50%	5.78%	5.00%	10.78%	11.08%	7.40%	3.68%
Jul-94	5.42%	5.68%	4.83%	10.51%	10.81%	7.58%	3.23%
Aug-94	5.50%	5.75%	4.50%	10.25%	10.55%	7.49%	3.06%
Sep-94	5.61%	5.86%	4.50%	10.36%	10.67%	7.71%	2.96%
Oct-94	5.48%	5.73%	4.50%	10.23%	10.53%	7.94%	2.59%
Nov-94	5.64%	5.89%	4.50%	10.39%	10.70%	8.08%	2.62%
Dec-94	5.86%	6.12%	4.50%	10.62%	10.95%	7.87%	3.08%
Jan-95	5.75%	5.99%	4.17%	10.16%	10.48%	7.85%	2.63%
Feb-95	5.59%	5.82%	4.17%	9.99%	10.30%	7.61%	2.69%
Mar-95	5.53%	5.76%	4.17%	9.93%	10.23%	7.45%	2.78%
Apr-95	5.45%	5.68%	4.17%	9.85%	10.15%	7.36%	2.79%
May-95	5.61%	5.84%	4.17%	10.01%	10.32%	6.95%	3.37%
Jun-95	5.43%	5.66%	4.17%	9.83%	10.12%	6.57%	3.55%
Jul-95	5.53%	5.75%	4.00%	9.75%	10.05%	6.72%	3.33%
Aug-95	5.41%	5.63%	4.13%	9.76%	10.06%	6.86%	3.20%

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Sep-95	5.28%	5.50%	4.25%	9.75%	10.04%	6.55%	3.49%
Oct-95	5.22%	5.44%	4.25%	9.69%	9.98%	6.37%	3.61%
Nov-95	4.96%	5.17%	4.25%	9.42%	9.69%	6.26%	3.43%
Dec-95	4.85%	5.06%	4.25%	9.31%	9.57%	6.06%	3.51%
Jan-96	4.83%	5.04%	4.38%	9.42%	9.69%	6.05%	3.64%
Feb-96	4.86%	5.07%	4.38%	9.45%	9.72%	6.24%	3.48%
Mar-96	4.96%	5.18%	4.38%	9.56%	9.83%	6.60%	3.23%
Apr-96	5.03%	5.26%	4.50%	9.76%	10.03%	6.79%	3.24%
May-96	5.85%	6.11%	4.50%	10.61%	10.94%	6.93%	4.01%
Jun-96	5.54%	5.79%	4.50%	10.29%	10.59%	7.06%	3.53%
Jul-96	5.85%	6.11%	4.50%	10.61%	10.94%	7.03%	3.91%
Aug-96	4.78%	5.00%	4.50%	9.50%	9.76%	6.84%	2.92%
Sep-96	5.12%	5.35%	4.50%	9.85%	10.13%	7.03%	3.10%
Oct-96	4.84%	5.05%	4.39%	9.44%	9.71%	6.81%	2.90%
Nov-96	4.64%	4.84%	4.39%	9.23%	9.49%	6.48%	3.01%
Dec-96	4.75%	4.96%	4.39%	9.35%	9.61%	6.55%	3.06%
Jan-97	4.88%	5.09%	4.39%	9.48%	9.75%	6.83%	2.92%
Feb-97	4.97%	5.16%	3.79%	8.95%	9.22%	6.69%	2.53%
Mar-97	5.00%	5.19%	3.79%	8.98%	9.25%	6.93%	2.32%
Apr-97	5.19%	5.39%	3.79%	9.18%	9.46%	7.09%	2.37%
May-97	5.00%	5.20%	4.09%	9.29%	9.57%	6.94%	2.63%
Jun-97	4.82%	5.01%	4.04%	9.05%	9.32%	6.77%	2.55%
Jul-97	4.76%	4.95%	4.04%	8.99%	9.25%	6.51%	2.74%
Aug-97	4.76%	4.95%	4.04%	8.99%	9.25%	6.58%	2.67%
Sep-97	4.60%	4.81%	4.52%	9.33%	9.58%	6.50%	3.08%
Oct-97	4.75%	4.97%	4.63%	9.60%	9.86%	6.33%	3.53%
Nov-97	4.52%	4.74%	4.87%	9.61%	9.86%	6.11%	3.75%
Dec-97	4.20%	4.41%	5.09%	9.50%	9.74%	5.99%	3.75%
Jan-98	4.42%	4.65%	5.10%	9.75%	9.99%	5.81%	4.18%
Feb-98	4.38%	4.60%	4.96%	9.56%	9.80%	5.89%	3.91%
Mar-98	4.37%	4.60%	5.25%	9.85%	10.09%	5.95%	4.14%
Apr-98	4.50%	4.73%	5.13%	9.86%	10.11%	5.92%	4.19%
May-98	4.48%	4.70%	4.96%	9.66%	9.91%	5.93%	3.98%
Jun-98	4.61%	4.84%	4.91%	9.75%	10.00%	5.70%	4.30%
Jul-98	4.96%	5.20%	4.92%	10.12%	10.40%	5.68%	4.72%

MOODY'S NATURAL GAS DISTRIBUTION UTILITIES
MONTHLY RISK PREMIUM ANALYSIS
1984 to 1999

MONTH	SPOT DIVID YIELD	EXPECT DIVID YIELD	ANALYSTS' GROWTH FORECASTS	COST OF EQUITY	RETURN ON EQUITY	YIELD ON U.S. 30 YR BONDS	RISK PREMIUM
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Aug-98	4.96%	5.20%	4.93%	10.13%	10.41%	5.54%	4.87%
Sep-98	4.69%	4.92%	4.94%	9.86%	10.12%	5.20%	4.92%
Oct-98	4.45%	4.66%	4.72%	9.38%	9.63%	5.01%	4.62%
Nov-98	4.57%	4.78%	4.62%	9.40%	9.65%	5.25%	4.40%
Dec-98	4.56%	4.77%	4.56%	9.33%	9.58%	5.06%	4.52%
Jan-99	5.01%	5.24%	4.54%	9.78%	10.05%	5.16%	4.89%
Feb-99	5.46%	5.70%	4.31%	10.01%	10.31%	5.37%	4.94%
Mar-99	5.74%	6.01%	4.75%	10.76%	11.08%	5.58%	5.50%
Apr-99	5.46%	5.72%	4.75%	10.47%	10.77%	5.55%	5.22%
May-99	5.27%	5.52%	4.75%	10.27%	10.56%	5.81%	4.75%
Jun-99	5.20%	5.44%	4.52%	9.96%	10.24%	6.04%	4.20%
Jul-99	5.11%	5.34%	4.55%	9.89%	10.17%	5.98%	4.19%
Aug-99	4.24%	4.43%	4.56%	8.99%	9.23%	6.07%	3.16%
Sep-99		0.00%	4.56%	4.56%	4.56%	6.07%	-1.51%
Oct-99		0.00%	4.56%	4.56%	4.56%	6.26%	-1.70%
Nov-99		0.00%	4.81%	4.81%	4.81%	6.15%	-1.34%
Dec-99		0.00%	4.95%	4.95%	4.95%	6.35%	-1.40%
						MEAN =	4.18%

Source:

Column 1: Month
Column 2: Moody's Natural Gas Utility Common Stocks Monthly
Dividend Yields from Moody's Public Utility Manual and News Reports
Column 3: Col. (2) x (1 + g) where 'g' is the growth rate from Col. (4)
Column 4: Avg. of IBES average long-term growth forecast for each company in the index
Column 5: Column 3 + Column 4
Column 6: Column 3 divided by 0.95 + Column 5
Column 7: U.S. 30-Year Treasury Bond Yield, Fed. Res. Board of Governors Release H.1
Column 8: Risk premium = Column 6 - Column 7

**MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS**

Year	Long-Term Governmen Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Natural Gas Distribution Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1954	2.72%	1,000.00				26.47					
1955	2.95%	965.44	(34.56)	27.20	-0.74%	28.10	1.38	6.16%	5.21%	11.37%	12.11%
1956	3.45%	928.19	(71.81)	29.50	-4.23%	28.23	1.48	0.46%	5.27%	5.73%	9.96%
1957	3.23%	1,032.23	32.23	34.50	6.67%	25.78	1.49	-8.68%	5.28%	-3.40%	-10.07%
1958	3.82%	918.01	(81.99)	32.30	-4.97%	38.71	1.57	50.16%	6.09%	56.25%	61.21%
1959	4.47%	914.65	(85.35)	38.20	-4.71%	39.59	1.66	2.27%	4.29%	6.56%	11.28%
1960	3.80%	1,093.27	93.27	44.70	13.80%	48.21	1.84	21.77%	4.65%	26.42%	12.62%
1961	4.15%	952.75	(47.25)	38.00	-0.92%	64.96	1.94	34.74%	4.02%	38.77%	39.69%
1962	3.95%	1,027.48	27.48	41.50	6.90%	59.73	2.02	-8.05%	3.11%	-4.94%	-11.84%
1963	4.17%	970.35	(29.65)	39.50	0.99%	64.62	2.18	8.19%	3.65%	11.84%	10.85%
1964	4.23%	991.96	(8.04)	41.70	3.37%	68.24	2.30	5.60%	3.56%	9.16%	5.80%
1965	4.50%	964.64	(35.36)	42.30	0.69%	64.31	2.48	-5.76%	3.63%	-2.12%	-2.82%
1966	4.55%	993.48	(6.52)	45.00	3.85%	53.50	2.61	-16.81%	4.06%	-12.75%	-16.60%
1967	5.56%	879.01	(120.99)	45.50	-7.55%	50.49	2.74	-5.63%	5.12%	-0.50%	7.04%
1968	5.98%	951.38	(48.62)	55.60	0.70%	53.80	2.81	6.56%	5.57%	12.12%	11.42%
1969	6.87%	904.00	(96.00)	59.80	-3.62%	43.88	2.93	-18.44%	5.45%	-12.99%	-9.37%
1970	6.48%	1,043.38	43.38	68.70	11.21%	52.33	3.01	19.26%	6.86%	26.12%	14.91%
1971	5.97%	1,059.09	59.09	64.80	12.39%	47.86	3.07	-8.54%	5.87%	-2.68%	-15.06%
1972	5.99%	997.69	(2.31)	59.70	5.74%	53.54	3.12	11.87%	6.52%	18.39%	12.65%
1973	7.26%	867.09	(132.91)	59.90	-7.30%	43.43	3.28	-18.88%	6.13%	-12.76%	-5.46%
1974	7.60%	965.33	(34.67)	72.60	3.79%	29.71	3.34	-31.59%	7.69%	-23.90%	-27.69%
1975	8.05%	955.63	(44.37)	76.00	3.16%	38.29	3.48	28.88%	11.71%	40.59%	37.43%
1976	7.21%	1,088.25	88.25	80.50	16.87%	51.80	3.70	35.28%	9.66%	44.95%	28.07%
1977	8.03%	919.03	(80.97)	72.10	-0.89%	50.88	3.93	-1.78%	7.59%	5.81%	6.70%
1978	8.98%	912.47	(87.53)	80.30	-0.72%	45.97	4.18	-9.65%	8.22%	-1.43%	-0.71%
1979	10.12%	902.99	(97.01)	89.80	-0.72%	53.50	4.44	16.38%	9.66%	26.04%	26.76%
1980	11.99%	859.23	(140.77)	101.20	-3.96%	56.61	4.68	5.81%	8.75%	14.56%	18.52%
1981	13.34%	906.45	(93.55)	119.90	2.63%	53.50	5.12	-5.49%	9.04%	3.55%	0.92%
1982	10.95%	1,192.38	192.38	133.40	32.58%	50.62	5.39	-5.38%	10.07%	4.69%	-27.89%
1983	11.97%	923.12	(76.88)	109.50	3.26%	55.79	5.55	10.21%	10.96%	21.18%	17.92%
1984	11.70%	1,020.70	20.70	119.70	14.04%	69.70	5.88	24.93%	10.54%	35.47%	21.43%
1985	9.56%	1,189.27	189.27	117.00	30.63%	76.58	6.22	9.87%	8.92%	18.79%	-11.83%
1986	7.89%	1,166.63	166.63	95.60	26.22%	90.89	5.71	18.69%	7.46%	26.14%	-0.08%
1987	9.20%	881.17	(118.83)	78.90	-3.99%	77.25	6.02	-15.01%	6.62%	-8.38%	-4.39%
1988	9.18%	1,001.82	1.82	92.00	9.38%	86.76	6.30	12.31%	8.16%	20.47%	11.08%
1989	8.16%	1,099.75	99.75	91.80	19.16%	117.05	6.58	34.91%	7.58%	42.50%	23.34%
1990	8.44%	973.17	(26.83)	81.60	5.48%	108.86	6.84	-7.00%	5.84%	-1.15%	-6.63%
1991	7.30%	1,118.94	118.94	84.40	20.33%	124.32	6.99	14.20%	6.42%	20.62%	0.29%
1992	7.26%	1,004.19	4.19	73.00	7.72%	138.79	7.14	11.64%	5.74%	17.38%	9.66%
1993	6.54%	1,079.70	79.70	72.60	15.23%	154.06	7.30	11.00%	5.26%	16.26%	1.03%
1994	7.99%	856.40	(143.60)	65.40	-7.82%	126.96	7.44	-17.59%	4.83%	-12.76%	-4.94%
1995	6.03%	1,225.98	225.98	79.90	30.59%	155.94	7.56	22.83%	5.95%	28.78%	-1.81%
1996	6.73%	923.67	(76.33)	60.30	-1.60%	166.64	7.91	6.86%	5.07%	11.93%	13.54%
1997	6.02%	1,081.92	81.92	67.30	14.92%	191.04	8.02	14.64%	4.81%	19.46%	4.53%
1998	5.42%	1,072.71	72.71	60.20	13.29%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.26%
1999	6.82%	848.41	(151.59)	54.20	-9.74%	160.00	8.16	-9.73%	4.60%	-5.12%	4.62%
MEAN					6.05%					11.87%	5.82%

Source: Moody's Public Utility Manual 1999 December stock prices and dividends
Bond yields from Ibbotson Assciates Table A-9 Long-Term Government Bonds Yields
December each year.

NATURAL GAS DISTRIBUTION UTILITIES
DCF ANALYSIS

Company	Beta (1)	% Current Divid Yield (2)	Analysts Growth Forecast (3)	% Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1 AGL Resources	0.60	6.4	6.0	6.8	12.8	13.1
2 Equitable Resources	0.60	2.5	12.3	2.9	15.2	15.3
3 MCN Energy Group	0.95	4.6	7.8	5.0	12.8	13.1
4 NICOR Inc.	0.60	5.0	6.2	5.3	11.5	11.8
5 Peoples Energy	0.70	6.1	5.7	6.4	12.1	12.5
6 Piedmont Natural Gas	0.60	5.2	5.7	5.5	11.2	11.5
7 Washington Gas Light	0.60	5.1	4.6	5.3	9.9	10.2
AVERAGE	**0.66**	**5.0**	**6.9**	**5.3**	**12.2**	**12.5**

Notes:
Column 1, 2: Value Line Investment Survey for Windows 95, 7/2000
Column 3: IBES long-term earnings growth forecast;
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

NATURAL GAS DISTRIBUTION UTILITIES
DCF ANALYSIS

Company	Beta (1)	% Current Divid Yield (2)	Value Line Proj Growth (3)	% Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1 AGL Resources	0.60	6.4	6.0	6.8	12.8	13.1
2 Equitable Resources	0.60	2.5	18.5	3.0	21.5	21.7
3 MCN Energy Group	0.95	4.6	2.0	4.7	6.7	7.0
4 NICOR Inc.	0.60	5.0	8.5	5.5	14.0	14.2
5 Peoples Energy	0.70	6.1	6.5	6.5	13.0	13.3
6 Piedmont Natural Gas	0.60	5.2	7.0	5.6	12.6	12.9
7 Washington Gas Light	0.60	5.1	7.5	5.5	13.0	13.3
AVERAGE	**0.66**	**5.0**	**8.0**	**5.4**	**13.4**	**13.6**

Notes:
Column 1, 2, 3: Value Line Investment Survey for Windows 95, 7/2000
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

GENERATION DIVESTITURE ELECTRIC UTILITIES
DCF ANALYSIS

	Company	% Current Divid Yield (1)	Analysts' Gth Fcst (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	CMP Group	3.1	12.5	3.5	16.0	16.1
2	Conectiv	5.3	5.3	5.6	10.9	11.2
3	Consol. Edison	7.1	3.7	7.4	11.1	11.5
4	DQE	4.1	6.6	4.3	10.9	11.2
5	Edison Int'l	5.7	9.2	6.2	15.4	15.7
6	Energy East Corp.	4.7	9.1	5.1	14.2	14.5
7	GPU Inc.	8.0	3.6	8.3	11.9	12.3
8	NSTAR	4.9	5.1	5.2	10.3	10.6
9	PG&E Corp.	4.8	6.7	5.1	11.8	12.1
10	Potomac Elec. Power	6.2	3.8	6.5	10.3	10.6
11	Sempra Energy	5.8	6.4	6.1	12.5	12.8
12	Sierra Pacific Res.	7.7	5.2	8.1	13.3	13.8
13	United Illuminating	6.5	2.3	6.6	8.9	9.3
	AVERAGE	**5.7**	**6.1**	**6.0**	**12.1**	**12.4**

Notes:
- Column 1: Value Line Investment Survey for Windows 95, 7/2000
- Column 2: IBES long-term earnings growth forecast;
  shaded cell: Zacks growth unavailable, Value Line projected earnings growth
- Column 3 = Column 1 times (1 + Column 2/100)
- Column 4 = Column 3 + Column 2
- Column 5 = (Column 3 /0.95) + Column 2

MOODY'S GENERATION DIVESTITURE UTILITIES
DCF ANALYSIS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	CMP Group	3.1	12.5	3.5	16.0	16.1
2	Conectiv	5.3	6.0	5.7	11.7	12.0
3	Consol. Edison	7.1	2.5	7.3	9.8	10.2
4	DQE	4.1	9.5	4.5	14.0	14.2
5	Edison Int'l	5.7	7.5	6.1	13.6	13.9
6	Energy East Corp.	4.7	10.0	5.2	15.2	15.4
7	GPU Inc.	8.0	3.0	8.3	11.3	11.7
8	NSTAR	4.9	6.5	5.3	11.8	12.0
9	PG&E Corp.	4.8	8.0	5.2	13.2	13.4
10	Potomac Elec. Power	6.2	5.0	6.6	11.6	11.9
11	Sempra Energy	5.8	5.0	6.0	11.0	11.4
12	Sierra Pacific Res.	7.7	8.5	8.4	16.9	17.3
13	United Illuminating	6.5	4.0	6.7	10.7	11.1
	AVERAGE	**5.7**	**6.8**	**6.0**	**12.8**	**13.1**

Notes:
Column 1, 2: Value Line Investment Survey for Windows 95, 1/00
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

NUI Corp DCF ANALYSIS

Company	Beta (1)	% Current Divid Yield (2)	Analysts Growth Forecast (3)	% Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
NUI Corp	0.70	3.7	13.2	4.2	17.4	17.6

Notes:
Column 1, 2: Value Line Investment Survey for Windows 95, 7/2000
Column 3: IBES long-term earnings growth forecast;
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

NUI Corp DCF ANALYSIS

Company	Beta (1)	% Current Divid Yield (2)	Proj EPS Growth (3)	% Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
NUI Corp	0.70	3.7	14.5	4.2	18.7	18.9

Notes:
Column 1, 2, 3: Value Line Investment Survey for Windows 95, 7/2000
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

CITY GAS COMPANY OF FLORIDA
13 MONTH AVERAGE COST OF CAPITAL
Projected Test Year Sept. 30, 2001

Type of Capital	Amount	Weight	Cost	Weighted Cost
Common Equity	$42,084,430	36.92%	11.70%	4.32%
Long Term Debt	$49,158,730	43.13%	6.54%	2.82%
Short Term Debt	$5,774,665	5.07%	8.00%	0.41%
Customer Deposit	$5,596,459	4.91%	6.73%	0.33%
Deferred Taxes	$10,488,832	9.20%	0.00%	0.00%
Tax Credit	$883,654	0.78%	0.00%	0.00%
Total	$113,986,770	100.00%		7.88%

CITY GAS COMPANY OF FLORIDA
PROJECTED CAPITAL STRUCTURE RATIOS
Projected Test Year Sept. 30, 2001

Type of Capital	Amount	Weight
Common Equity	$42,084,430	43.38%
Long Term Debt	$49,158,730	50.67%
Short Term Debt	$5,774,665	5.95%
Total	$97,017,825	100.00%

CITY GAS COMPANY OF FLORIDA
PROJECTED CAPITAL STRUCTURE RATIOS
Projected Test Year Sept. 30, 2001

Type of Capital	Amount	Weight
Common Equity	$42,084,430	46.12%
Long Term Debt	$49,158,730	53.88%
Total	$91,243,160	100.00%

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBITS OF

THOMAS E. SMITH

ON BEHALF OF CITY GAS COMPANY OF FLORIDA

DOCKET NO. 000768-GU

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A. My name is Thomas E. Smith. My office is located at 550 Route 202-206, Bedminster, New Jersey, 07921.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of City Gas Company of Florida ("NUI City Gas" or the "Company").

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by NUI Corporation ("NUI"). NUI City Gas is a division of NUI.

Q. WHAT IS YOUR POSITION WITH NUI?

A. I am the Director of Energy Planning for NUI Corporation. I am also currently overseeing the operation of NUI's Rates Department.

Q. WHAT IS THE SCOPE OF YOUR DUTIES AS DIRECTOR OF ENERGY PLANNING AT NUI?

A. As Director of Energy Planning I am responsible for planning, acquisition, and management of the gas supply portfolio of the utility divisions of NUI, including NUI City Gas.

Q. WHAT IS THE SCOPE OF YOUR DUTIES WITH REGARD TO NUI'S RATES DEPARTMENT?

A. In overseeing NUI 's Rates Department I am responsible for supervising all of the Rate Department's daily operations. This includes the development of monthly rates, such as PGAs in several of the Company's jurisdictions, parity prices when customers have alternate energy sources, and other periodic rates, such as demand side management and weather normalization. I am also responsible for presenting testimony regarding the Rate Department's analysis in connection with the development of such rates.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I am a licensed Professional Engineer in the State of New Jersey. I received a Bachelor of Science degree in mechanical engineering from Newark College of Engineering in 1970. In 1976, I received a Master of Science degree in mechanical engineering from the New Jersey Institute of Technology, formerly Newark College of Engineering. During my term of employment at NUI, I have attended the Institute of Gas Technology courses on Gas Distribution Engineering and Economics for Managers, the American Gas Association's (AGA) Rate Fundamentals course, the Center for

Professional Advancement's course on Rate Setting in Public Utilities and numerous conferences, seminars, and symposiums on matters relating to my job function. Currently, I am a member of the American Society of Mechanical Engineers and from 1979 to 1988 I was a member of the AGA Rate Committee. I am also a contributing author to the 4th Edition of the Gas Rates Fundamentals book sponsored and prepared by the AGA Rate Committee and published by AGA. I have been an instructor on Cost of Service at the AGA Gas Rates Fundamentals course at Madison, Wisconsin. In my tenure at NUI, prior to my current assignment as Director of Energy Planning, I was the Director of Rates and Tariffs for Elizabethtown Gas Company of NUI.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will sponsor the Company's proposed tariff modifications and both the interim and permanent rate designs. In support of my permanent rate design testimony, I have prepared a cost of service study by customer class for the projected test year ended September 30, 2001. In addition, I have reviewed competitive energy alternatives for each customer class. My testimony will provide the Commission with a description of the methodology used in preparing the cost of service study by customer class. I will describe how I employed the results of the cost of service study and the review of competitive energy alternatives in establishing the permanent rate design. I will also discuss the Company's turn back of pipeline capacity to Florida Gas Transmission Company. We expect that this turn back of capacity will reduce the PGA rate to our sales customers at approximately the same time that rates from this case become effective. This will to some degree mitigate the price increases our customers would see as a result of the base rate increase being sought in this filing. Finally, I will discuss non-rate changes to existing tariffs.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Exhibit No. ___ (TS-1) is the list of MFR Schedules I am sponsoring. Exhibit No.____ (TS-2) shows the interim rate increase allocation among the classes. Exhibit No.___ (TS-3) is a bypass cost analysis for large customers. Exhibit No. ___(TS-4) is a competitive cost analysis. Exhibit No.___ (TS-5) presents the rate of return under present and proposed rates. Exhibit No.___(TS-6) presents the unit costs by rate class. Exhibit No.___(TS-7) shows the revenues from the present and proposed rates. Exhibit No.___(TS-8) is a comparison of present and proposed rates.

Q. HOW DO YOU PROPOSE TO ALLOCATE INTERIM RATE RELIEF?

A. Exhibit No.____(TS-2) which is a summary of MFR schedule F-10 presents the allocation of the Company's requested interim rate relief. The Company proposes to allocate the increase on an equal percentage basis across all classes through an adjustment to the energy or transportation charge. The Company requests that it be permitted to implement the interim rate changes through the aggregate combined classes as shown on Exhibit No. ___(TS-2).

Q. PLEASE SUMMARIZE HOW YOU DESIGNED THE RATES PROPOSED BY THE COMPANY IN THIS PROCEEDING.

A. I first performed a cost of service study, by rate class, to determine what rates would be using a fully embedded cost of service approach. However, as I describe later, this study produced uneconomical rates for large volume classes that can readily access alternative energy sources, thus making them very price sensitive. Therefore, as a second step, I further analyzed these customer classes and modified the study to allocate to them a more appropriate share of fixed distribution costs. This modified study is the basis for the rate design proposed in this proceeding.

Q. PLEASE DESCRIBE THE OBJECTIVES IN PERFORMING A COST OF SERVICE STUDY.

A. The objectives of performing a cost of service study are:

- To develop "unbundled" cost information by function (production, storage, transmission, and distribution) and classification (customer, commodity, demand, and revenue) for each service classification in order to design cost based rates within each service classification.
- To determine the rate of return for each of City Gas'

customer service classifications based upon its present rates in order to provide guidance for the equitable allocation of the Company's requested revenue increase.

Q. PLEASE DESCRIBE THE COST OF SERVICE APPROACH THAT YOU FOLLOWED.

A. As a preface to my remarks on cost of service, I would like to point out that in the gas industry, as in any regulated industry, there is a need to allocate commonly used plant. There are different ways to do this. In Staff's Cost of Service (COS) methodology, capacity is allocated based on peak and average demand usage. This means that large volume and interruptible customers receive a higher allocation of costs than under an approach that recognizes that all customers are responsible only for the minimum system required to connect them, while only firm service customers are responsible for the additional cost of the system necessary to meet their peak needs. In an increasingly competitive environment, the peak and average methodology, to the extent it imposes costs on customers who do not cause those costs to be incurred, could cause inappropriate price signals to consumers which would be detrimental to achieving economic efficiency in the use of gas facilities and services.

Bearing that in mind, in order to design rates for each service classification, I have essentially followed the Florida Public Service Commission Staff's standard COS methodology, including the presentation format that is contained in prescribed MFR forms. This approach is also consistent with the study used in the Company's last rate case, Docket No. 960502-GU. Both my proposed rate design and many of the Company's proposed tariff modifications are the result of using the FPSC Staff COS methodology with the adjustments described and working closely with the marketing group to develop customer choices in this burgeoning competitive environment.

Q. WHAT ARE THE MAJOR STEPS IN PERFORMING A COST OF SERVICE STUDY?

A. A cost of service study uses a basic three-step process of cost analysis:

1. Functionalization of rate base and expenses, such as production, storage, transmission, and distribution;
2. Classification of functionalized components into demand, commodity, customer, and revenue categories; and
3. Allocation of each component among customer classes of service.

Q. PLEASE DESCRIBE THE FIRST STEP IN MORE DETAIL.

A. The first step in performing a cost of service study is to functionalize costs into their most basic "functions" (i.e., production, storage, transmission, and distribution). This is primarily a mechanical process because costs are accounted for and recorded by the Company's Accounting Department in accordance with the FERC Uniform System of Accounts. This functionalization is presented on MFR Schedule H-3, pages 2 through 5. Pages 2 and 3 functionalize the overall cost of service. Pages 4 and 5 functionalize rate base.

Q. PLEASE DESCRIBE THE SECOND STEP IN MORE DETAIL.

A. The second step in a cost of service study is the classification of costs into categories. Costs are classified according to the system design and operating characteristics which cause those costs to be incurred. Classification into categories is necessary in order to identify the major costs and to allocate those costs to customer classes based on each class' responsibility for the costs.

Q. WHAT COST CATEGORIES DID YOU IDENTIFY FOR PURPOSES OF YOUR COST STUDY?

A. There are four traditional cost categories that are included in Staff's methodology and that I used in the cost study:

1. customer costs;
2. capacity costs or demand costs;
3. commodity costs;
4. revenue costs.

Q. PLEASE DESCRIBE CUSTOMER COSTS.

A. Customer costs are costs which are incurred to attach a customer to the system, meter the customer's usage and maintain the customer's account, as well as other costs which are a function of the number of customers served. Customer costs continue to be incurred whether or not a customer uses any gas.

Q. PLEASE DESCRIBE CAPACITY OR DEMAND COSTS.

A. Capacity or demand costs relate to the maximum delivery requirements of the system. That is, these costs relate to the diameter the pipe must be to meet the maximum demand on the system at any one time. As with customer costs, capacity costs continue to be incurred whether or not a customer uses any gas.

Q. PLEASE DESCRIBE COMMODITY COSTS.

A. Commodity costs are those which vary with the quantity of gas sent out or transported to customers. The cost of gas is the clearest example of a commodity cost.

Q. WHAT ARE REVENUE COSTS?

A. Revenue costs are items which are a function of revenues, such as gross receipts taxes.

Q. SINCE YOU HAVE USED THE COMMISSION STAFF'S COST OF SERVICE METHODOLOGY, IS IT NECESSARY TO DESCRIBE THE CLASSIFICATION OF EACH COST?

A. No. The classification of each functionalized cost component is detailed on MFR Schedule H-3, pages 2 through 5. I have not changed any of the "classifiers" identified by Staff.

Q. PLEASE DESCRIBE THE THIRD STEP IN A COST OF SERVICE STUDY.

A. After the total cost of service has been classified, the final step is to derive the allocation factors to be used to distribute the classified costs to the customer classes.

Q. HOW WERE THE CUSTOMER CLASSES DETERMINED?

A. A customer class is a relatively homogeneous group of customers having similar service requirements and usage characteristics. Customer classifications consistent with the Company's major tariff schedules were used for the study because such classifications represent substantially homogeneous customers. Consistent with present tariffs, these customer classes fall into two major service categories – sales service and transportation service. In the sales service category the classes are residential (RS), gas lighting (GL), commercial and industrial (CS), large commercial (LCS), interruptible preferred (IP), and natural gas vehicles (NGV). In the transportation service category the classes are small commercial and industrial (SCT), commercial and industrial (CTS), interruptible (IT), contract interruptible (C-IT), interruptible large volume (ILVT) and contract interruptible large volume (C-ILVT). Grouping by customer class is important because different types of customers have different service requirements and thus impose different costs on the system. Identifying and understanding the cost elements of each class is essential for designing rates. However, aggregating similar classes together for ultimate rate design is often necessary to assure consistency and logic in the rates, to address administration of the tariff and to assure that service options under the tariff are understood by the markets we serve. Later in my testimony I will discuss how aggregating into broader classes was employed in developing the proposed rates.

Q. PLEASE DESCRIBE MFR SCHEDULE H-2, PAGES 9 AND 10.

A. MFR Schedule H-2, pages 9 and 10, presents the calculation of each of the allocation factors by rate class.

Q. PLEASE EXPLAIN HOW YOU ALLOCATED CUSTOMER COSTS.

A. Customer costs were allocated on the basis of the relative number of customers in each class, with the larger customers weighted to recognize their higher level of customer costs. For instance, a residential customer will have one meter reading a month, while a very large customer may have an automatic metering device and be monitored daily, which is relatively more costly to do. In addition, a larger customer will have a larger, more expensive meter, regulator and service line.

Q. HOW DID YOU DETERMINE THE CUSTOMER WEIGHTINGS?

A. The weightings used were derived from the relative investment in service lines, meters and regulators required to serve representative customers in each class. The weightings can be found on MFR Schedule E-7 which is supported by Mr. Wall.

Q. HOW WERE COMMODITY COSTS ALLOCATED?

A. Commodity costs were allocated on the basis of annual sales quantity.

Q. HOW DID YOU ALLOCATE CAPACITY COSTS?

A. Capacity costs were allocated on the basis of peak month and average monthly sales volume. This method recognizes that while the size of the pipes installed to make up the gas distribution system are predicated on the need to meet the peak requirements of the customers served from the system, they also serve to allow the general gas flow requirements through the system during non peak periods. Thus, the peak and average method allocates capacity costs in relation to each customer class' contribution to both the peak month and the average month in equal proportion.

Q. ARE THERE OTHER PEAK AND AVERAGE METHODS THAT COULD BE EMPLOYED IN ALLOCATING CAPACITY COSTS?

A. Yes. In general if a peak and average method is employed it usually will be based on peak day and average day or, when reliable data is available, peak hour and average hour. From an engineering design point-of-view, a gas distribution system is designed and constructed to meet the peak hour gas requirements. Therefore, the further away from a peak hour the method moves the greater the potential it is not properly recognizing the true contribution to the peak requirements designed into the distribution system.

Q. WHAT WOULD BE THE IMPACT OF EMPLOYING PEAK AND AVERAGE DAY IN THE PEAK AND AVERAGE ALLOCATION METHOD?

A. When peak day and average day data are used in place of peak month and average month data, more capacity costs are allocated to those classes that have a poorer load factor – i.e. whose peak demand for gas is much larger than their average demand for gas. Generally those are the residential and small commercial classes. Since capacity related costs make up the majority of the cost of service, even moderate swings can have significant impact on overall cost allocation to classes. Thus, use of monthly data can have the effect of allocating too much cost to higher load factor classes.

Q. HOW WERE REVENUE COSTS ALLOCATED?

A. Revenue costs were allocated on the basis of gross revenues by class.

Q. PLEASE DESCRIBE THE RESULTS OF THE ALLOCATIONS.

A. The results of the allocation are presented in MFR Schedule H-2, pages 3 through 8. The total cost of service by class is shown on MFR Schedule H-2, pages 3 through 6. MFR Schedule H-2, pages 7 and 8, presents the allocation of rate base to each rate class.

Q. YOU MENTIONED EARLIER THAT THIS TRADITIONAL, EMBEDDED COST OF SERVICE STUDY PRODUCED UNECONOMICAL RATES FOR TWO CLASSES OF CUSTOMERS THAT ARE PRICE SENSITIVE. PLEASE EXPLAIN.

A. In the large volume classes, C-ILVT and C-ITS, the cost study using the peak and average month allocation methodology for capacity costs produced a rate that would make it economical for these customers to bypass our system. The primary reason for this result is that there are so few customers in this class. Under the traditional cost of service approach, the twelve customers in these classes were being allocated more than $5.14 million above the cost of what it would be to install dedicated facilities to each of them. This result is clearly unreasonable. When an allocation methodology assigns more cost than a class or customer would incur if it were the only customer on a system, it is time to temper the allocation with the rule of reason.

Q. HOW DID YOU MODIFY THE STAFF'S COST OF SERVICE METHODOLOGY TO ADDRESS THE CONCERN ABOUT THE OVER-ALLOCATION OF COSTS TO THE LARGE VOLUME CLASSES?

A. I made one change to Staff's methodology. In evaluating the results of the Staff's methodology, I determined that the large volume customer classes C-ILVT and C-ITS were allocated a disproportionate share of capacity cost. The allocation factor of capacity costs for these classes were 15.8% and 2.1% respectively, resulting in $3.35 million of capacity cost being allocated to twelve customers. This left $15.15 million in capacity costs to be allocated among the remaining 119,422 customers.

To correct this disproportionate allocation, I had our Utility Operations Department calculate the cost of bypass for these customers by determining their location in relation to the interstate pipeline. This bypass cost analysis is presented in Exhibit ___(TS-3) to my testimony. I then adjusted one element of Staff's model -- mains -- to reduce the amount of main cost allocated to this class to an amount equal to the customers' incremental cost to bypass City Gas' system. Any greater allocation would provide the customers an incentive to leave the system.

Q. **WHAT DID YOU DO NEXT?**

A. After performing the additional analysis of the classes I just described, I compared the resulting rates for all customer classes to a competitive cost analysis that I had prepared by rate class. The purpose was to assure myself that the rates that the Company is proposing are reasonable.

Q. **PLEASE EXPLAIN WHY IT IS APPROPRIATE TO USE THIS TYPE OF COMPETITIVE COST ANALYSIS.**

A. Cost of service by class should be the starting point in designing rates, but other factors influence the final rate design. The most important of these is the Company's ability to price its services competitively, given the evolving nature of deregulation in the natural gas industry and the value of service that the Company is providing to the customer. Another factor, which I will discuss later, is the need to consider historical rate structure and levels.

Q. **PLEASE DISCUSS WHY THE ABILITY TO PRICE SERVICES COMPETITIVELY IS AN IMPORTANT FACTOR IN RATE DESIGN.**

A. In Florida, particularly South Florida, natural gas is not a monopoly. All of the Company's customers have access to electricity. Additionally, many of the customers have access to viable fuel alternatives, such as propane and various grades of fuel oil. Large industrial and commercial customers often have the ability to use low cost residual grades of oil or even coal. Unlike electricity, virtually every end use of gas can be replaced with some other form of energy. In addition, larger customers may have the option to physically bypass the utility by connecting directly to the interstate pipeline. Therefore, City Gas' rates must be sensitive to the broad energy market and physical bypass alternatives otherwise, the Company risks the loss of customers and demand for gas service.

Q. PLEASE DESCRIBE THE COMPETITIVE COST ANALYSIS THAT YOU PERFORMED.

A. Exhibit ___ (TS-4) presents a comparison of current and proposed rates by class of customer with prices for alternative energy sources such as electricity, propane and oil. For Residential and Small Commercial customers, the energy alternatives are primarily electricity and propane. For larger Commercial and Industrial customers, the alternative energy sources also include various grades of oil. For very large industrial customers, coal, other exotic energy sources, and physical bypass of City Gas may be competitive alternatives.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO THE RESIDENTIAL CUSTOMERS?

A. The first page of this Exhibit presents a graphical comparison of the residential present and proposed rates inclusive of all adjustments and riders at their current levels (PGA, ECCR, and CRA) with the incremental electric costs and propane gas costs for various usage levels over a month. All costs are expressed in equivalent therms and reflect the different BTU value of the energy form or its end use efficiency in relation to natural gas. It is clear from this graph that current residential gas costs have a competitive advantage over propane. Page two of this exhibit shows the price of residential gas service as a percent of electric costs. The final proposed rates for gas, when adjusted for the reduction in capacity costs that will be going into effect shortly, will still maintain a reasonable price advantage over incremental electric cost. One would also expect electric costs to rise somewhat in the near future reflecting the general increase in oil and gas prices that have occurred recently.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO THE COMMERCIAL CUSTOMERS?

A. Pages three and four of Exhibit No.___ (TS-4) present a cost comparison for small commercial usage. At gas usage above 20 therms a month gas, even at proposed rates, generally has an increasing price advantage over the competing electric and propane energy sources. Below 20 therms usage electric will generally have the price advantage. Pages five and six of the exhibit are cost comparisons for large commercial usage levels. Again, gas, under both present and proposed rates, maintains a competitive price advantage in the higher usage levels – above 500 therms per month.

Q. WHAT DOES THE ANALYSIS SHOW WITH REGARD TO LARGE INDUSTRIAL CUSTOMERS?

A. Page seven of Exhibit No.___(TS-4) presents a cost comparison of the large industrial gas rates with current oil prices. It is clear from this graph that current and proposed gas rates are well above #6 residual oil prices. Number 2 fuel oil has a price advantage over gas for the Interruptible Preferred sales class. However, the large volume transportation rates still appear to have a slight price advantage over #2 fuel oil. It is the large industrial class that is most at risk to competitive energy costs. In setting the proposed rates to the large industrial classes I had to recognize the high level of competition in this class.

Q. HOW DID YOU DEVELOP THE FINAL PROPOSED RATES ?

A. The final rates were designed on the basis of the cost of service by class, the competitive considerations discussed above and a review of the current structure of rates and classes. Although the cost of service study incorporates twelve distinctive classes, many of the classes are either very small or similar in basic characteristics. The transportation classes are very similar to sales classes in the markets they serve. Before developing the final rates I combined the twelve classes down into five consolidated common rate classes – Residential (RS, GL), Small Commercial and Industrial (CS, NGV, SCTS), Large Commercial & Industrial (LCS, CTS), Interruptible Service Industrial (IP, ITS, CI-TS) and Large Interruptible Industrial Service (LVT, CI-LVT). These combined classes are reflected in the present structure of the Company's tariff and rates. Changes from the historical structure should be done gradually to avoid rate shock and possible market distortion. I next summarized the results of the cost study into these combined classes and used this to guide the final rate design with the objective of having each combined class generate a rate of return as close to the overall rate of return as could be achieved without producing excess competitive risk in the interruptible service classes. Exhibit No. ___(TS-5) presents the rate of return under present and proposed rates for the individual classes and the combined classes. Only the Interruptible Service Industrial combined class has proposed rates that will generate returns appreciably different from the overall return.

Q. HOW MUCH REVENUE WILL THE PROPOSED RATES PRODUCE?

A. The final rates and charges were designed to produce $40.757 million. This is the revenue requirement presented by Mr. Clancy in his testimony. Exhibit No. ___(TS-7) presents the revenue by individual classes and combined classes for present and proposed rates. As can be seen in this exhibit, the large industrial and commercial classes will be receiving proportionately more of the increase than will the residential class.

Q. PLEASE COMPARE THE PROPOSED RATES TO THE PRESENT RATES.

A. A comparison of present and proposed rates is presented in MFR

Schedule E-2. A summary of this schedule is attached as Exhibit No.____ (TS-8). These rates and charges will recover the aggregate cost of service.

Q. PLEASE DISCUSS THE PROPOSED CUSTOMER CHARGES.

A. The proposed Customer Charges were changed from present levels based primarily on the unit cost data from the cost study. Exhibit No. ___(TS-6) presents the unit cost information by individual classes and combined classes. The customer charge for residential customers was set at $7.50, rather than the $12.75 shown in the unit cost study, in consideration of competitive electric prices and an objective of having all customers who consume at least 10 therms generate base revenue sufficient to cover the customer costs. The proposed customer charge for commercial and industrial (C&IS) sales customers was set at $20.00. Competitive concerns at the very low usage levels precluded setting the charge at the $54 level shown in the unit cost study. The Customer Charge for Large Commercial was set at $50.00, a significant increase from present levels, but still only 80% of the full customer cost as presented in the unit cost study. The customer charge for Interruptible preferred was increased from $50.00 to $100.00, bringing it up to 50% of the customer costs shown in the unit cost study.

All transportation customer charges were set higher than their respective sales service counterparts to recognize the higher level of costs associated with customer accounting, billing and the balancing of gas receipts and deliveries for transportation service.

Q IS THE COMPANY PROPOSING TO CHANGE ITS OTHER CHARGES?

A. Yes. Connection charges for residential customers are proposed to increase from $20.00 to $30.00. Nonresidential connection charges are proposed to increase from $45.00 to $60.00. Reconnection charges are *proposed at the same respective rates.* The return check charge is proposed to increase from $15.00 to $25.00, or 5% of the face value of the check, whichever is greater. The change of account charge is proposed to increase from $15.00 to $20.00. These changes better reflect the Company's true costs.

Q. WHAT CHANGES TO ITS TARIFF IS THE COMPANY PROPOSING?

A. Tariff language modifications are being proposed to clarify that the Third Party Supplier (TPS) will be responsible to pay any monthly cash-outs resulting from transportation imbalances --- the difference between the gas they delivered and the amount of gas the customers they serve used.

The monthly Standby Charge has been increased to $.785 per therm, reflecting updated costs for this service.

Minimum annual bill language was added to the LCS rate schedule. This language apparently had been inadvertently left out of the rate schedule.

A provision was added to both the IP and the ITS rate schedules on failure to comply with curtailment notices. The proposed provision would permit the Company to place a customer who does not curtail service onto a higher cost firm service until the customer provides proof they can curtail their service when requested. This provision would be in addition to the existing penalty for the actual occurrence of noncompliance. This provision was deemed necessary to assure that customers who are served under interruptible service schedules in fact are able to curtail their gas use.

Other tariff language modifications throughout the tariff are proposed for clarification or to simplify administration.

Q. YOU INDICATED THAT ONE OF YOUR DUTIES IS TO MANAGE THE GAS SUPPLY PORTFOLIO FOR NUI CITY GAS. PLEASE DESCRIBE THE STEPS THE COMPANY HAS TAKEN TO ASSURE THAT THE LEVEL OF CAPACITY IT HAS UNDER CONTRACT WITH THE INTERSTATE PIPELINE, FLORIDA GAS TRANSMISSION, IS APPROPRIATE FOR THE DEMANDS FOR GAS SERVICE ON ITS SYSTEM.

A. The first step was to evaluate the demand for gas supply by the markets served by City Gas out over the next five years. This involves assessing the changing markets being served, especially the expanding migration of commercial and industrial accounts to transportation service. As these market changes occur they will impact the Company's obligation to provide merchant service, particularly as it relates to maintaining capacity on the interstate pipeline, FGT. The result of the first step is a load duration curve that provides a picture of the gas demand shape to be served over the forecast period. The second step was to review the portfolio of supply and capacity assets that City Gas has under contract and overlay those capabilities on the load duration curve established in step 1. The third step was to identify the capacity levels that were in excess of the forecasted need and determine what opportunities there were to realign those contracts. In this step we identified two opportunities to realign our capacity contracts on FGT. The first opportunity was an "Open Season" issued in the spring of 1999 by FGT for a proposed expansion on their system. The Company identified a level of FTS-2 capacity that it offered back to FGT to support FGT's proposed expansion. FGT has accepted this capacity return contingent on the expansion going forward. The expansion is scheduled to be in operation by May of 2001 at which time the reduction in the Company's FTS-2 contract will occur. The second opportunity to realign capacity on FGT was the FTS-1 capacity contract renewal date of August 31, 2000. The Company has notified FGT of the reduced levels of FTS-1 capacity it will contract for commencing September 2000.

Q. HAVE THESE STEPS HELPED TO MINIMIZE THE POTENTIAL FOR STRANDED CAPACITY COSTS AS YOUR CUSTOMERS MIGRATE TO TRANSPORTATION SERVICE?

A. Yes. We anticipate that commercial and industrial customers will continue to migrate to transportation service where they have many more options available to them to control their gas costs. As they leave bundled sales service, the level of capacity that the Company needs to have available on the Interstate Pipeline is reduced. Shedding this excess capacity as opportunities arise helps to keep the portfolio of capacity the Company holds on the interstate pipeline in line with the changing needs of the system. This avoids or at least greatly mitigates long term stranded capacity costs.

Q. WILL THE TIMING OF REDUCTIONS IN CONTRACT LEVELS OF INTERSTATE PIPELINE CAPACITY HELP MINIMIZE THE LEVEL OF POSSIBLE RATE INCREASE CUSTOMERS WILL INCUR FROM ANY INCREASE GRANTED IN THIS DOCKET?

A. Yes, that should be the case. The reduction in the demand charges paid to FGT associated with the reduction in the FTS-1 contracted capacity will begin in September 2000. The annualized impact is a reduction in costs to our customers through the PGA of $1.1 million. The reduction in demand charges from our reduction in FTS-2 contracted capacity, is expected to begin in May 2001. The annualized impact is an additional reduction in costs to our customers through the PGA of $2 million.

Q. THE COMPANY IS UNDERTAKING A MAJOR PIPELINE CONSTRUCTION PROJECT KNOWN AS THE CLEWISTON EXPANSION PROJECT. DOES THIS PIPELINE HAVE ANY POTENTIAL BENEFIT TO THE COMPANY IN CONTROLLING

FUTURE COSTS OF GAS SUPPLY?

A. Mr. Gruber in his testimony addresses the new markets that this pipeline will serve and future growth potential in the area where the pipeline will be constructed and describes potential supply related benefits. AS NUI's Director of Energy Planning one of my primary responsibilities is to plan for and acquire gas supply to meet the needs of the utility divisions of NUI. In this endeavor my goals are to assure reliability and keep costs as low as reasonably possible. In carrying out the supply function for the Utility divisions of NUI it has been my experience when multiple interstate pipelines are available to provide service the forces of competition result in increased options being offered for service. In addition, the pipelines recognize they are competing to provide service and, even though their rates are regulated by FERC, they must keep their rates for service in line with the other competing pipelines or risk losing market share. I concur with Mr. Gruber that the Clewiston Expansion Project has the potential to provide interconnections with other interstate pipelines and storage services that are being proposed to serve the growing natural gas needs for electric power generation. Such interconnections in the future will promote competition among interstate pipelines serving the Company that will act to keep gas supply and capacity costs lower. Also, such interconnections will provide some system redundancy that can provide protection against events such as that which occurred at the FGT Perry Compressor station in August of

1998 that significantly limited gas transmission into much of Florida.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

LIST OF MFR SCHEDULES SPONSORED BY THOMAS E. SMITH

Schedule		Title
E-1	pp. 1-3	Cost of Service – Therm Sales and Revenues
E-2	pp. 1&2	Cost of Service – Revenues Calculated at Present and Proposed Rates
E-4	pp. 1-3	Cost of Service – Calculation of Peak Monthly Sales and Transportation Volume
E-5	pp. 1-12	Cost of Service – Monthly Bill Comparison Present and Proposed Rates
E-9		Cost of Service - Tariff Sheets
F-10	p. 1	Calculation of Interim Rate Relief - Deficiency Allocation
H-1	pp. 1&2	Cost of Service - Proposed Rates
H-1	pp. 3&4	Cost of Service - Proposed Rate Design
H-1	pp. 5-8	Cost of Service - Rate of Return by Class Present and Proposed Rates
H-1	pp. 9&10	Cost of Service - Revenue Deficiency
H-1	pp. 11&12	Cost of Service - Summary
H-2	pp. 1&2	Cost of Service - Summary
H-2	pp. 3-6	Allocation of Cost of Service to Customer Class
H-2	pp. 7&8	Allocation of Rate Base to Customer Class
H-2	pp. 9&10	Development of Allocation Factors
H-2	p. 11	Cost of Service - Summary

H-3	p. 1	Cost of Service - Summary
H-3	pp. 2-3	Classification of Expenses and Derivation of Cost of Service by Cost Classification
H-3	p. 4	Classification of Rate Base - Plant
H-3	p. 5	Classification of Rate Base - Accumulated Depreciation

ALLOCATION OF INTERIM RATE RELIEF

RATE SCHEDULE	THERM SALES	TOTAL REVENUES	DOLLAR INCREASE	% INCREASE	INCREASE Per Therm
RS	18,900,628	$ 16,870,368	$ 1,020,130	6.05%	$ 0.05397
GL	44,110	$ 17,666	$ 1,068	6.05%	$ 0.02422
C&IS	34,544,014	$ 8,097,121	$ 489,623	6.05%	$ 0.01417
LCS	1,955,289	$ 326,177	$ 19,724	6.05%	$ 0.01009
IP	1,013,998	$ 210,465	$ 12,727	6.05%	$ 0.01255
NGV	46,585	$ 10,320	$ 624	6.05%	$ 0.01340
SCTS	3,684,674	$ 748,757	$ 45,276	6.05%	$ 0.01229
CTS	7,101,494	$ 1,264,777	$ 76,479	6.05%	$ 0.01077
ITS	12,593,536	$ 1,644,072	$ 99,415	6.05%	$ 0.00789
CI-ITS	2,310,208	$ 282,040	$ 17,055	6.05%	$ 0.00738
ILT	8,891,960	$ 765,799	$ 46,307	6.05%	$ 0.00521
CI-LVT	11,159,316	$ 962,122	$ 58,178	6.05%	$ 0.00521
TOTAL	102,245,811	$ 31,199,683	$ 1,886,605	6.05%	$ 0.01845

COMBINED RATE SCHEDULES					
RS, GL	18,944,738	$ 16,888,034	$ 1,021,198	6.05%	$ 0.05390
C&IS, SCTS,NGV	38,275,273	$ 8,856,198	$ 535,523	6.05%	$ 0.01399
LGS, CTS	9,056,783	$ 1,590,954	$ 96,203	6.05%	$ 0.01062
IP, ITS, CI-ITS	15,917,742	$ 2,136,577	$ 129,196	6.05%	$ 0.00812
ILT, CI-LVT	20,051,276	$ 1,727,920	$ 104,485	6.05%	$ 0.00521
TOTAL	102,245,811	$ 31,199,683	$ 1,886,605	6.05%	$ 0.01845

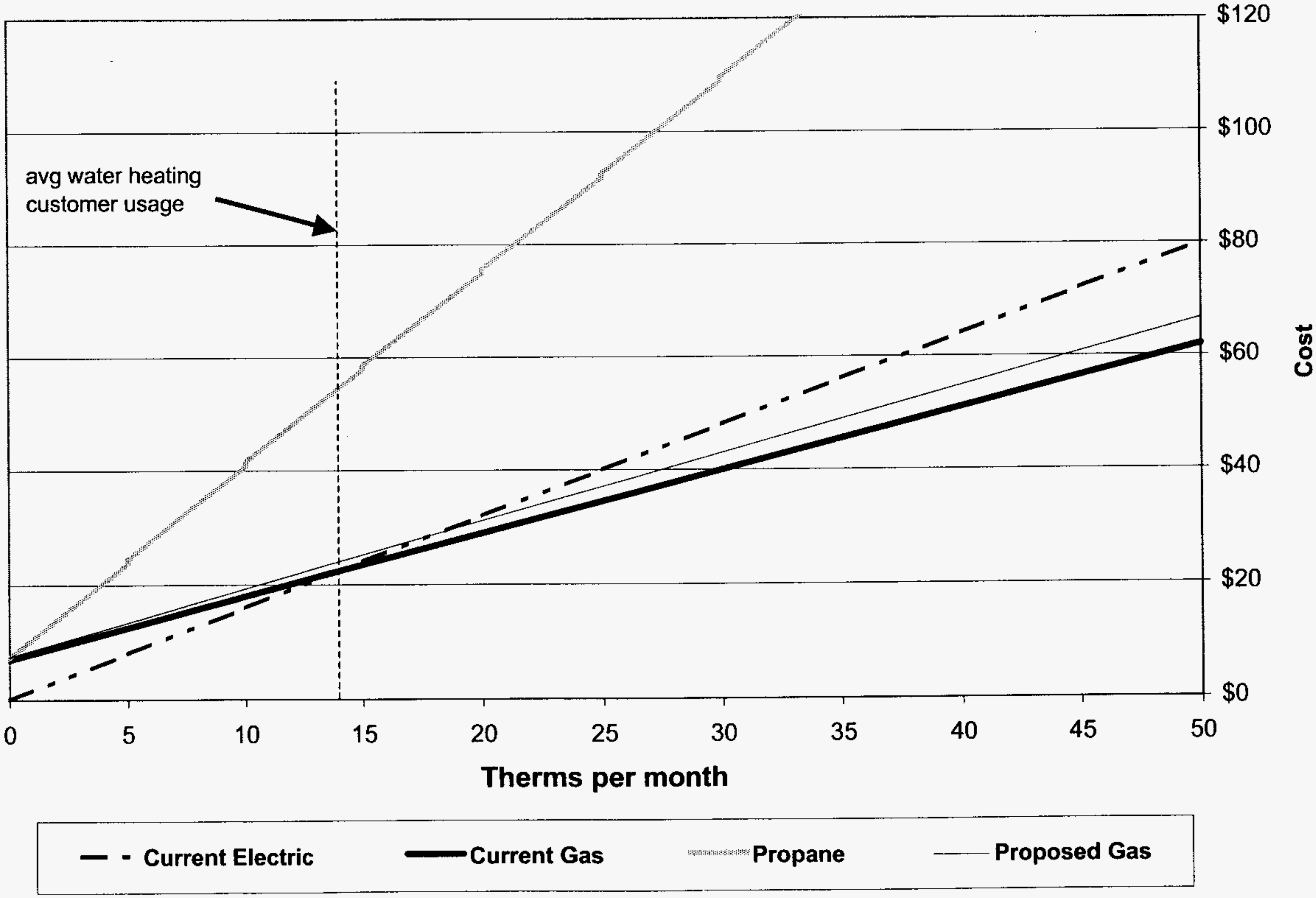
BYPASS ANALYSIS

Customer Name & Location	(1) Customer Rate Class	(2) Customer MDQ in Dth	(3) Customer Annual Needs In Dth	(4) Distance to Bypass City Gas in feet	(5) Pipe Size Nominal Dia. (Inches)	(6) Estimated Cost Per Foot	(7) Estimated Cost of Bypass Pipleine (col 6X col 4)	(8) Estimated cost of Gate Station @ Interstate Pipleine	(9) Estimate of Total Facilities Cost to Bypass*
Customer 1	CI-LVT	2,100	207,000	7,800	4	$ 44.00	$ 343,200	$ 150,000	$ 493,200
Customer2	CI-LVT	950	296,520	4,000	4	$ 50.00	$ 200,000	$ 150,000	$ 350,000
Customers 3 & 4	CI-LVT	1,500	429,480	300	4	$ 50.00	$ 15,000	$ 150,000	$ 165,000
Customer 5	CI-LVT	400	87,190	3,500	4	$ 50.00	$ 175,000	$ 150,000	$ 325,000
Customer 6**	CI-LVT	1,295	194,430	-	-	$ -	$ -	$ -	$ 956,560
Customer 7	CI-LVT	600	179,450	1,500	4	$ 50.00	$ 75,000	$ 150,000	$ 225,000
Customer 8**	CI-LVT	CI-LVT	4,000	488,000	-	$ -	$ -	$ -	$ 1,354,107
Customer 9**	CI-LVT	CI-LVT	2,000	244,000	-	$ -	$ -	$ -	$ 677,054
Subtotal	**9**	**6,845**	**1,394,070**	**17,100**			**$ 733,200**	**$ 750,000**	**$ 4,545,921**
Customer 10	CI ITS	500	93,620	5,000	4	$ 50.00	$ 250,000	$ 150,000	$ 400,000
Customer 11**	CI - ITS	450	99,010	8,000	-	$ -	$ -	$ -	$ 490,892
Customer 12	CI -ITS	350	48,020	180	4	$ 50.00	$ 9,000	$ 150,000	$ 159,000
Subtotal	**3**	**1,300**	**240,650**	**13,180**			**$ 259,000**	**$ 300,000**	**$ 1,049,892**
Total	12	8,145	1,634,720	30,280			$ 992,200	$ 1,050,000	$ 5,595,813

* Does not include meter and regulation equipment at customer site.

** By Pass was not a practical alternative. Main cost allocated using Peak and Average method for these customers.

Residential Energy Cost Comparison



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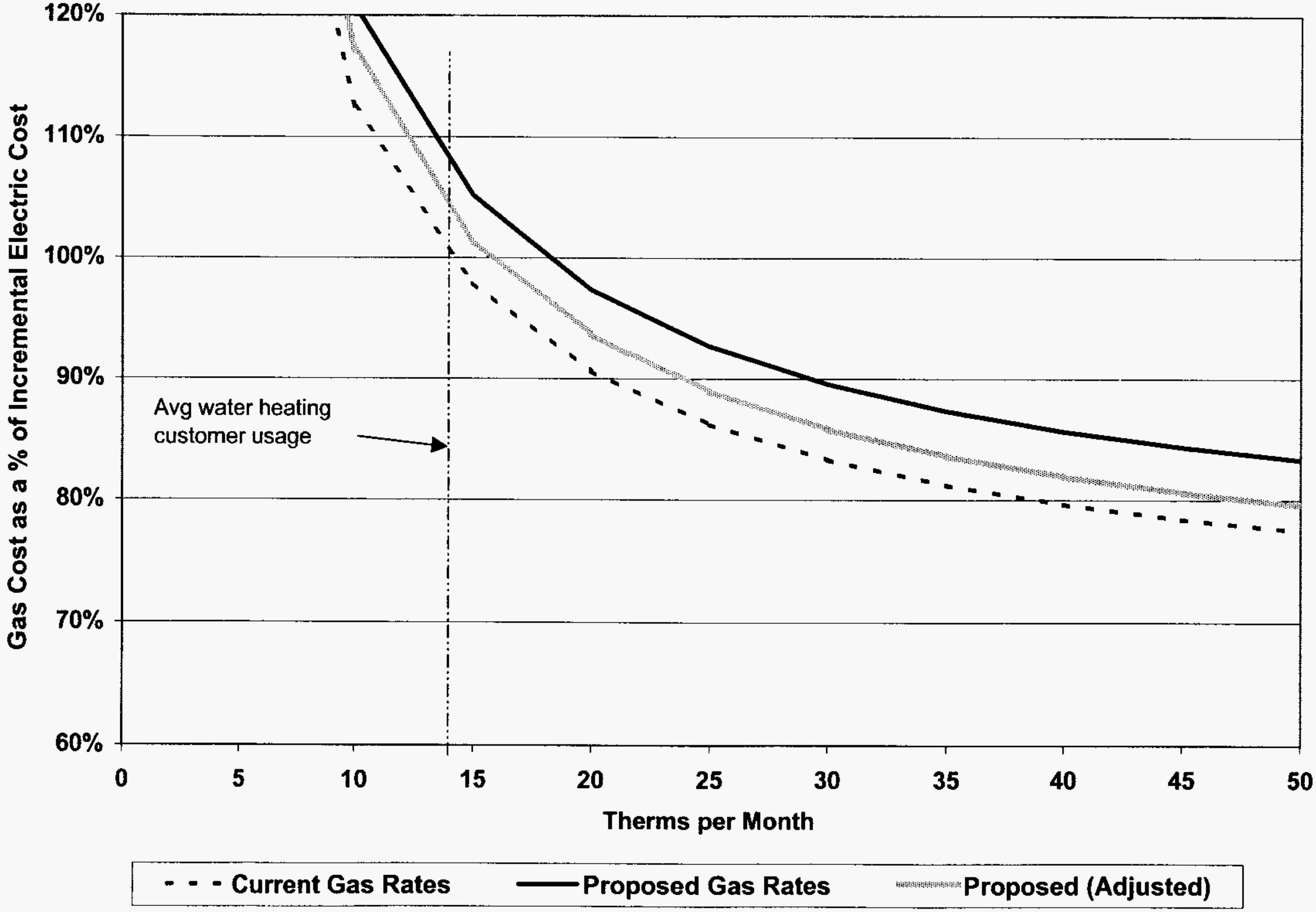
Residential Energy Cost Comparison



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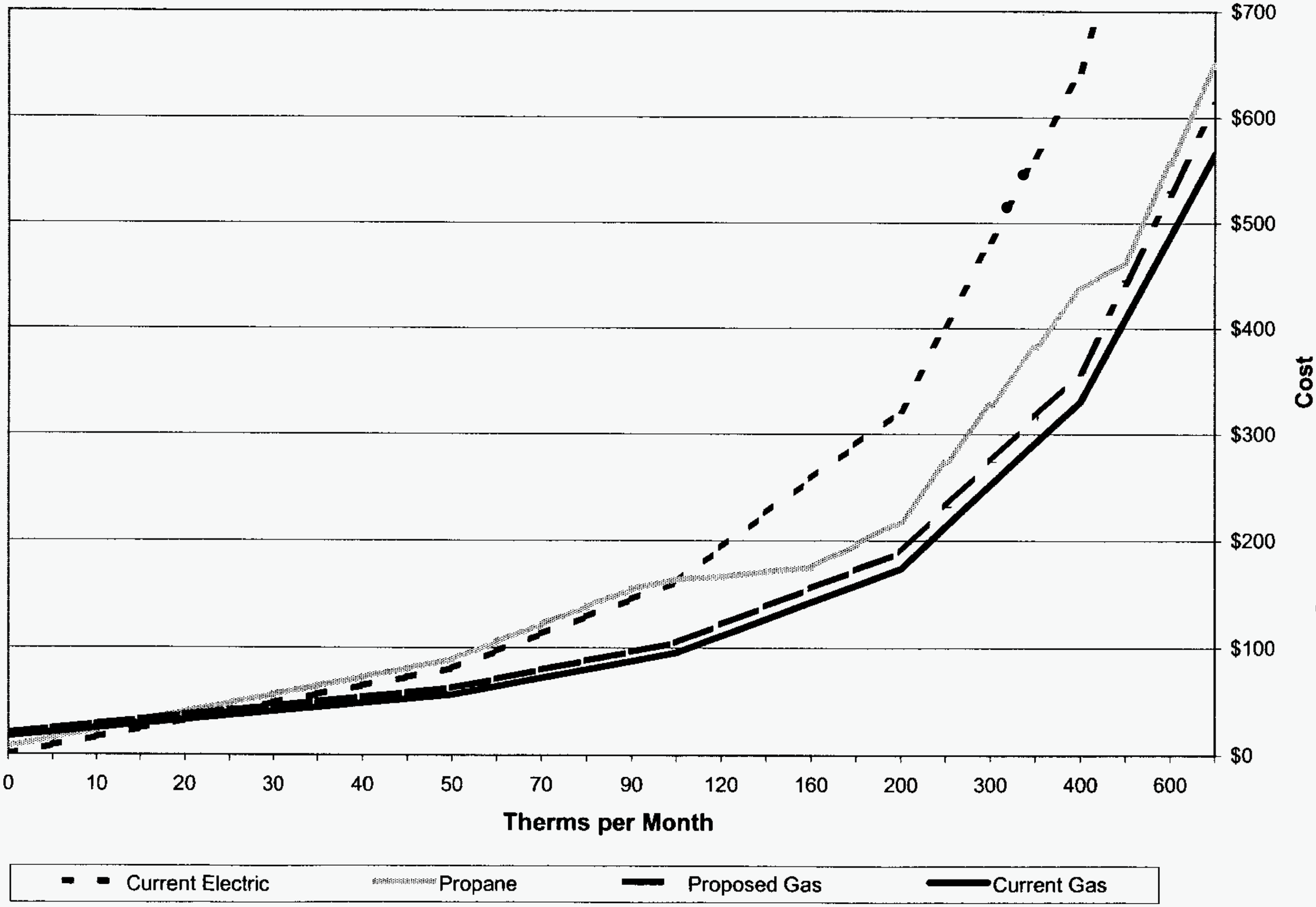
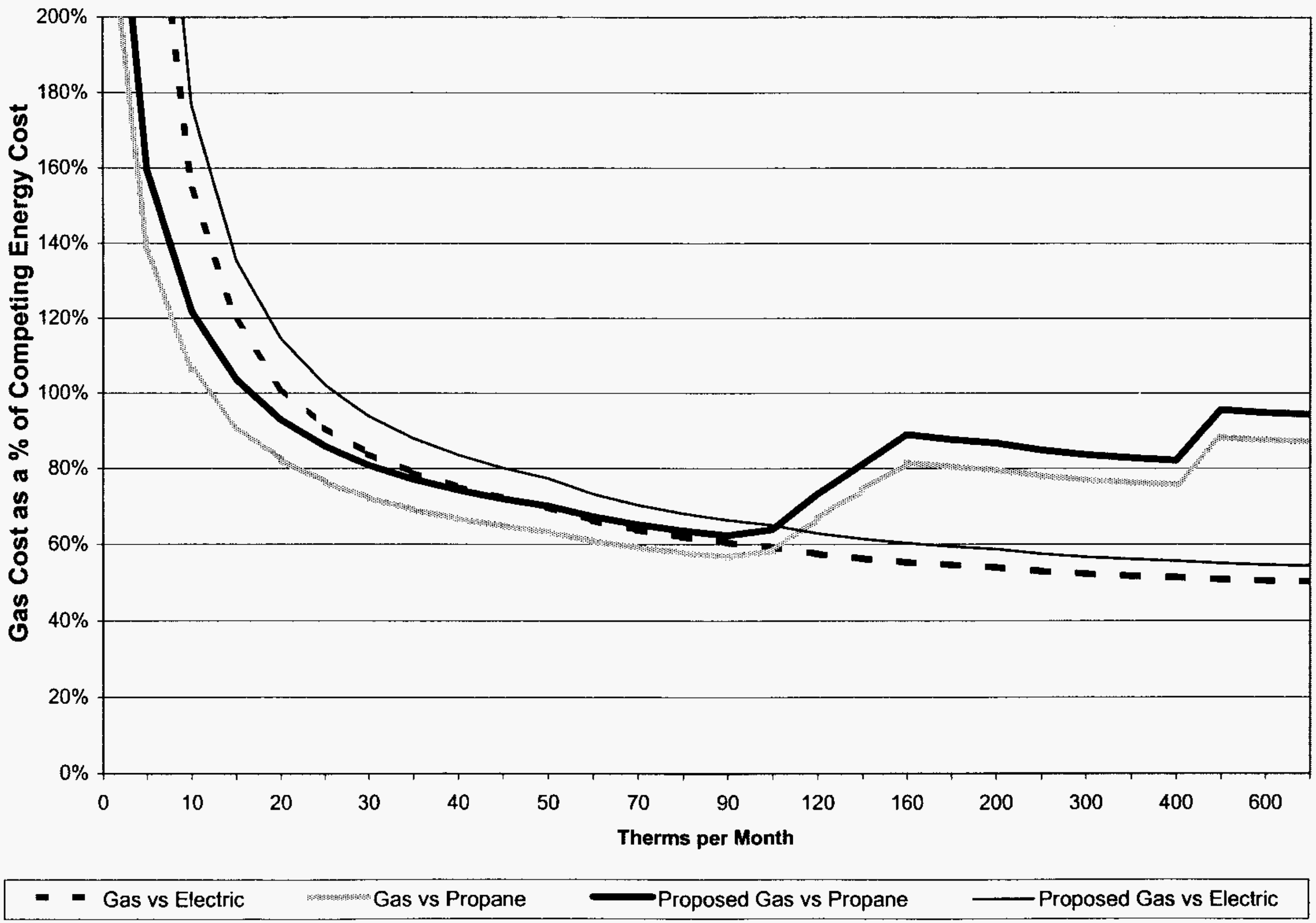
Small Commercial Energy Cost Comparison



Small Commercial Energy Cost Comparison



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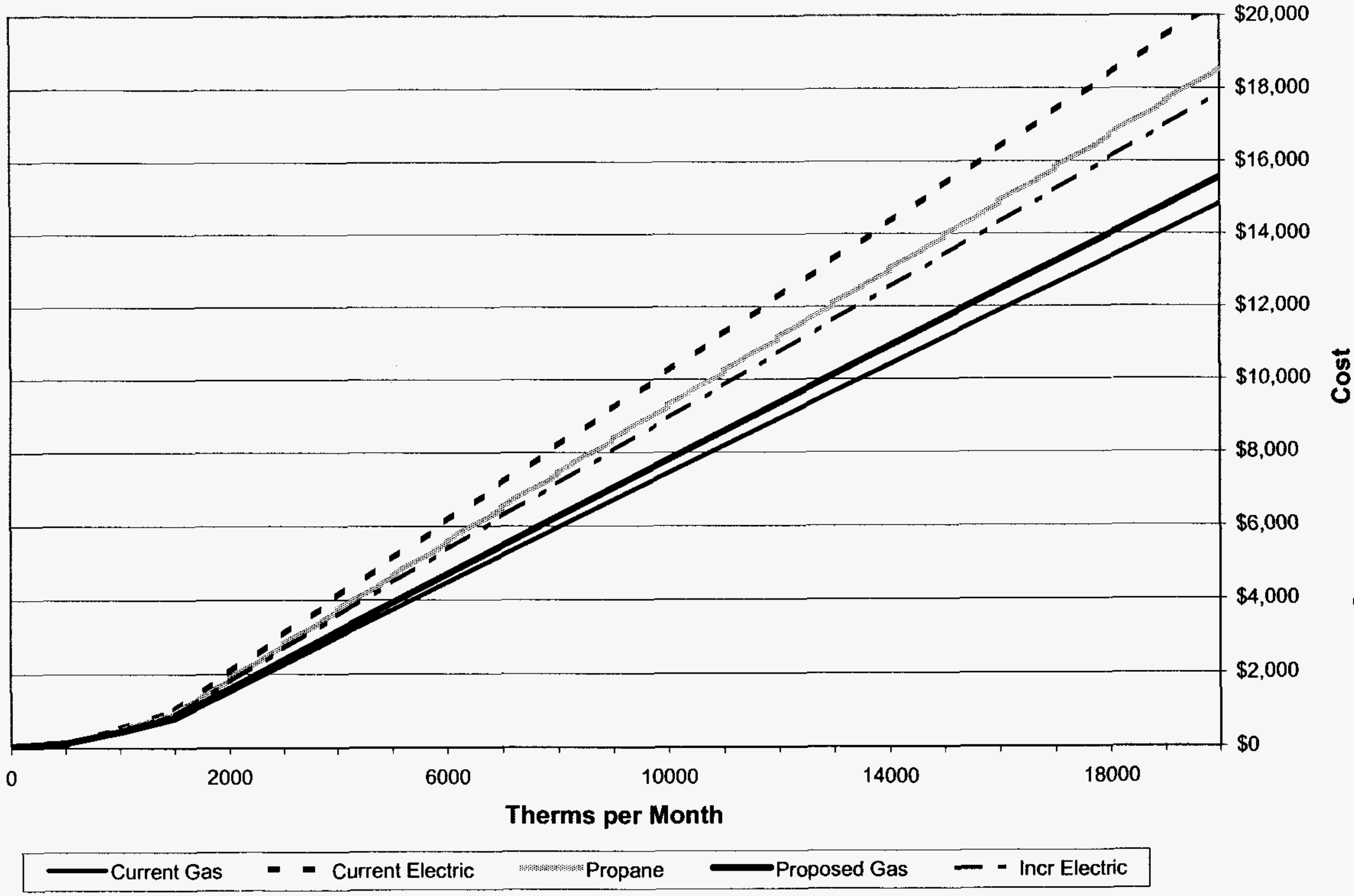
Large Commercial Energy Cost Comparison



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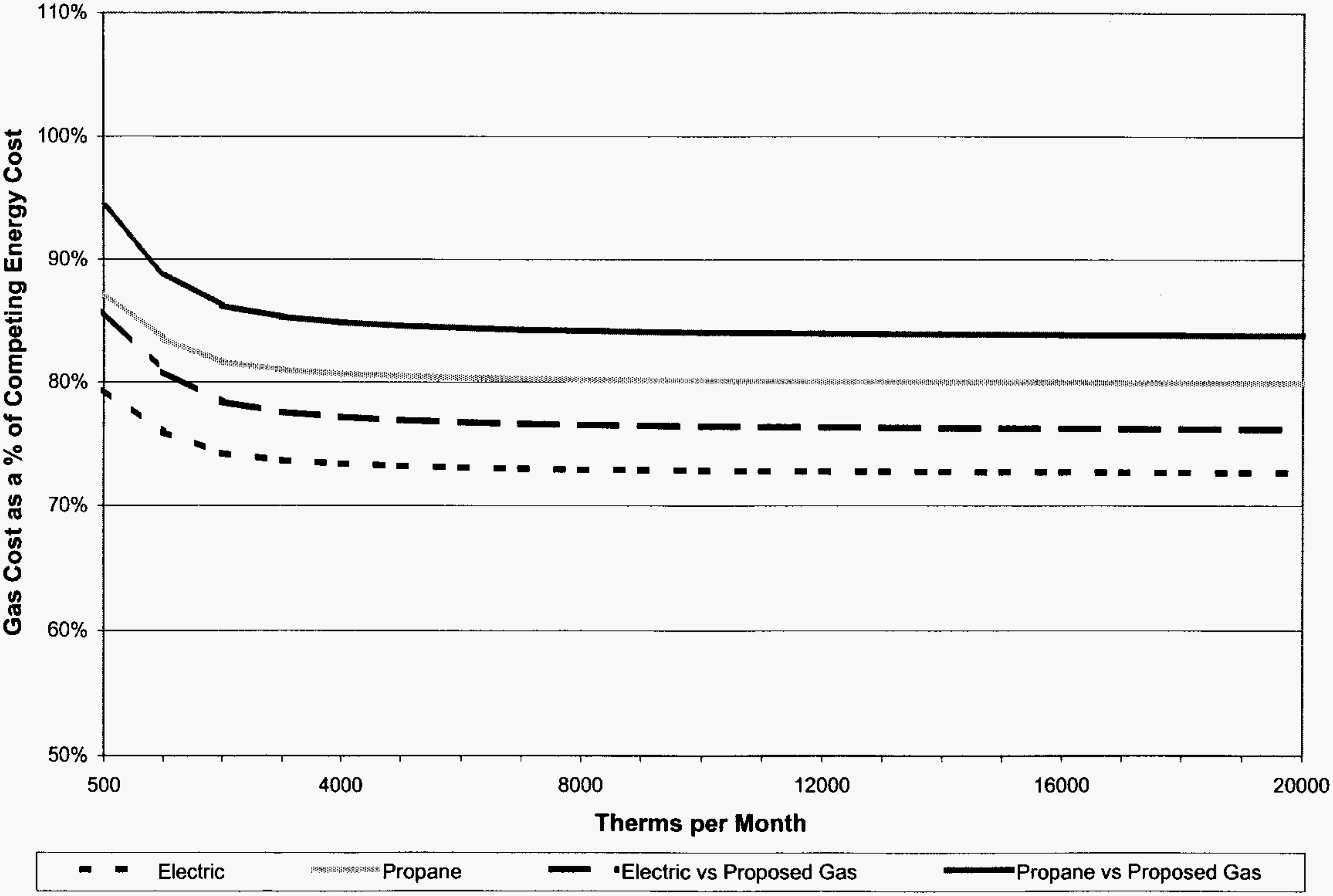
Large Commercial Energy Cost Comparison



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Large Industrial Energy Cost Comparison

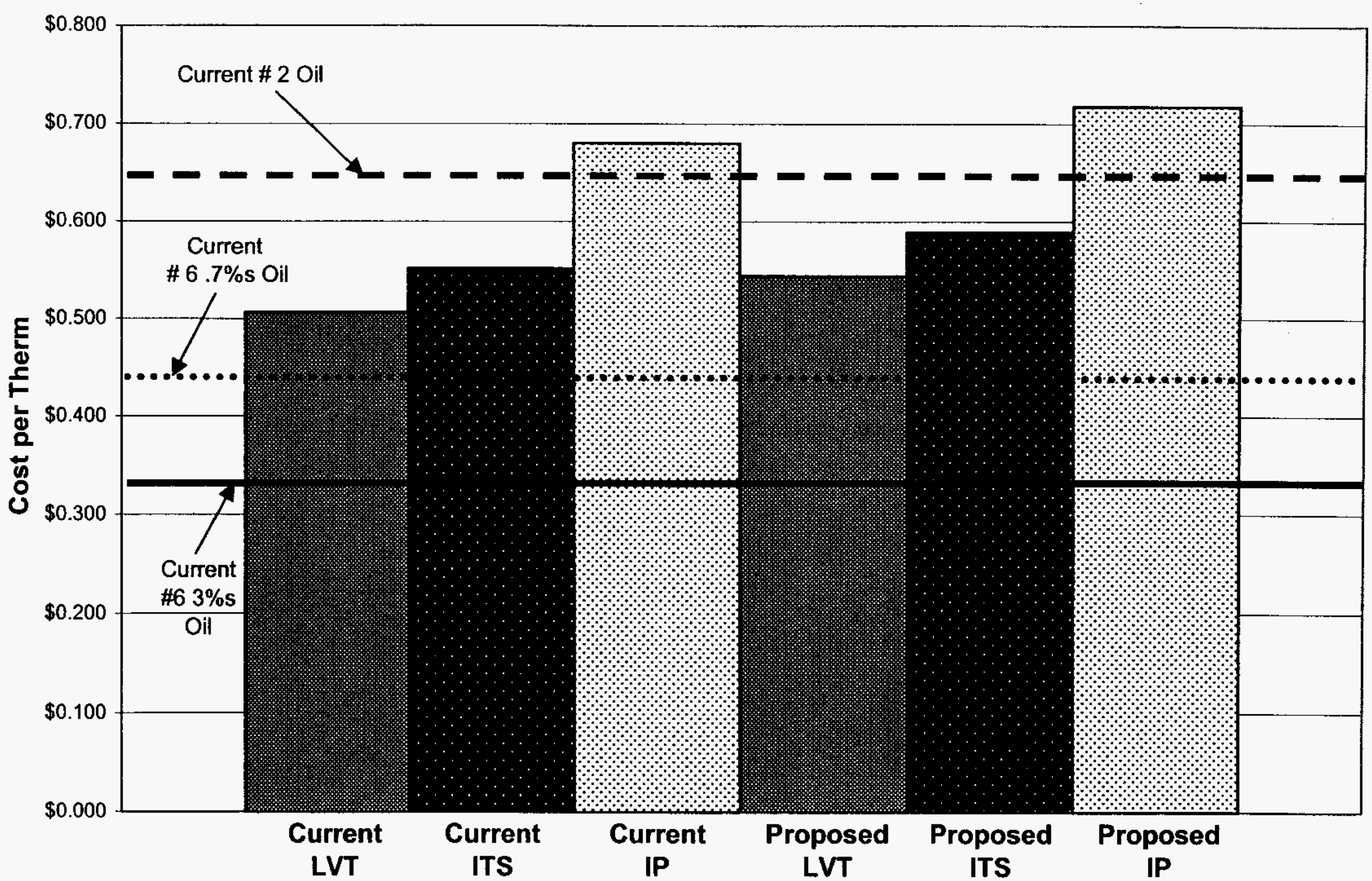

Exhibit No.___(TS-4)
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Rate of Return by Rate Class

Class	Present Rates ROR	Present Rates Index	Proposed Rates ROR	Proposed Rates Index
SALES				
RESIDENTIAL	5.94%	1.48	7.97%	1.01
GAS LIGHTING	-7.16%	-1.79	-4.59%	-0.58
COMMERCIAL & INDUSTRIAL	3.72%	0.93	9.06%	1.15
LARGE COMMERCIAL	5.16%	1.29	8.44%	1.07
INTERRUPT PREFERRED	-2.62%	-0.65	1.01%	0.13
NATURAL GAS VEHICLES	-25.54%	-6.37	-23.30%	-2.96
TRANSPORTATION				
SMALL COMMERCIAL	3.20%	0.80	8.85%	1.12
COMMERCIAL	4.28%	1.07	7.30%	0.93
INTERRUPT	-1.03%	-0.26	2.48%	0.32
CONTRACT INTERRUPT	3.53%	0.88	7.93%	1.01
INTERRUPT LARGE VOLUME	-6.93%	-1.73	-2.84%	-0.36
CONTRACT INTERRUPT LV	6.43%	1.60	14.87%	1.89
Total Company	**4.01%**	**1.00**	**7.88%**	**1.00**

Rate of Return by Consolidated Common Rate Classes

Class	Present Rates ROR	Present Rates Index	Proposed Rates ROR	Proposed Rates Index
RESIDENTIAL				
(RS,GL)	5.91%	1.47	7.94%	1.01
SMALL COMMERCIAL & INDUSTRIAL				
(CS, NGV, SCTS)	3.57%	0.89	8.99%	1.14
LARGE COMMERCIAL & INDUSTRIAL				
(LCS, CTS)	4.42%	1.10	7.49%	0.95
INTERRUPTIBLE SERVICE INDUSTRIAL				
(IP, ITS, CI-TS)	-0.48%	-0.12	3.16%	0.40
LARGE INTERRUPTIBLE INDUSTRIAL SERVICE				
(LVT, CI-LVT)	1.47%	0.37	8.29%	1.05
Total Company	**4.01%**	**1.00**	**7.88%**	**1.00**

Unit Cost Summary by Rate Class

Class	Customer ($/Customer)	Capacity ($/therm)	Commodity ($/therm)
SALES			
RESIDENTIAL	$ 12.75	$ 0.22982	$ 0.01628
GAS LIGHTING	$ 19.64	$ 0.27670	$ 0.02412
COMMERCIAL & INDUSTRIAL	$ 54.41	$ 0.21913	$ 0.01851
LARGE COMMERCIAL	$ 61.89	$ 0.19264	$ 0.01751
INTERRUPT PREFERRED	$ 202.98	$ 0.31257	$ 0.02458
NATURAL GAS VEHICLES	$ 116.27	$ 0.38153	$ 0.03289
TRANSPORTATION			
SMALL COMMERCIAL	$ 67.30	$ 0.24853	$ 0.01904
COMMERCIAL	$ 64.76	$ 0.21159	$ 0.01832
INTERRUPT	$ 191.29	$ 0.27658	$ 0.02317
CONTRACT INTERRUPT	$ 157.63	$ 0.17643	$ 0.01909
INTERRUPT LARGE VOLUME	$ 475.68	$ 0.33052	$ 0.02856
CONTRACT INTERRUPT LV	$ 273.43	$ 0.07992	$ 0.01642
Total Company	**$ 13.55**	**$ 0.16404**	**$ 0.01496**

Unit Cost Summary
by Consolidated Common Rate Classes

Class	Customer ($/Customer)	Capacity ($/therm)	Commodity ($/therm)
RESIDENTIAL (RS,GL)	$ 12.76	$ 0.22997	$ 0.01630
SMALL COMMERCIAL & INDUSTRIAL (CS, NGV, SCTS)	$ 56.88	$ 0.22776	$ 0.01866
LARGE COMMERCIAL & INDUSTRIAL (LCS, CTS)	$ 64.29	$ 0.20831	$ 0.01818
INTERRUPTIBLE SERVICE INDUSTRIAL (IP, ITS, CI-TS)	$ 187.32	$ 0.26135	$ 0.02269
LARGE INTERRUPTIBLE INDUSTRIAL SERVICE (LVT, CI-LVT)	$ 350.36	$ 0.13387	$ 0.02104
Total Company	**$ 13.55**	**$ 0.16404**	**$ 0.01496**

Revenue Summary by Rate Class

Class	Present Rates	Proposed Rates	Increase	Percent Increase
SALES				
RESIDENTIAL	$ 17,710,598	$ 20,019,042	$ 2,308,444	13.03%
GAS LIGHTING	$ 30,804	$ 36,370	$ 5,566	18.07%
COMMERCIAL & INDUSTRIAL	$ 7,265,647	$ 9,338,050	$ 2,072,403	28.52%
LARGE COMMERCIAL	$ 287,400	$ 349,922	$ 62,522	21.75%
INTERRUPT PREFERRED	$ 103,025	$ 134,952	$ 31,927	30.99%
NATURAL GAS VEHICLES	$ 192	$ 243	$ 51	26.56%
TRANSPORTATION				
SMALL COMMERCIAL	$ 2,724,811	$ 3,610,661	$ 885,850	32.51%
COMMERCIAL	$ 1,387,001	$ 1,680,999	$ 293,998	21.20%
INTERRUPT	$ 1,434,426	$ 1,839,896	$ 405,470	28.27%
CONTRACT INTERRUPT	$ 313,297	$ 403,373	$ 90,076	28.75%
INTERRUPT LARGE VOLUME	$ 523,009	$ 751,836	$ 228,827	43.75%
CONTRACT INTERRUPT LV	$ 1,794,428	$ 2,591,284	$ 796,856	44.41%
Total Company	**$ 33,574,638**	**$ 40,756,626**	**$ 7,181,988**	**21.39%**

Revenue Summary
by Consolidated Common Rate Classes

Class	Present Rates	Proposed Rates	Increase	Percent Increase
RESIDENTIAL				
(RS,GL)	$ 17,741,402	$ 20,055,412	$ 2,314,010	13.04%
SMALL COMMERCIAL & INDUSTRIAL				
(CS, NGV, SCTS)	$ 9,990,650	$ 12,948,953	$ 2,958,304	29.61%
LARGE COMMERCIAL & INDUSTRIAL				
(LCS, CTS)	$ 1,674,401	$ 2,030,921	$ 356,520	21.29%
INTERRUPTIBLE SERVICE INDUSTRIAL				
(IP, ITS, CI-TS)	$ 1,850,748	$ 2,378,220	$ 527,472	28.50%
LARGE INTERRUPTIBLE INDUSTRIAL SERVICE				
(LVT, CI-LVT)	$ 2,317,437	$ 3,343,120	$ 1,025,683	44.26%
Total Company	**$ 33,574,638**	**$ 40,756,626**	**$ 7,181,988**	**21.39%**

Comparison of Present and Proposed Rates

	Present Rates	Proposed Rates
Residential:		
Customer charge	$ 7.00	$ 7.50
Energy charge per therm	$ .46349	$ .54709
Gas Lighting:		
Customer charge	---	---
Energy charge per therm	$ .46349	$ .54709
Commercial and Industrial Firm:		
Customer charge	$ 17.00	$ 20.00
Energy charge per therm	$ .20259	$ .26549
Large Commercial Firm:		
Customer charge	$ 35.00	$ 50.00
Energy charge per therm	$ .16336	$ .19839
Interruptible preferred:		
Customer charge	$ 50.00	$ 100.00
Energy charge per therm	$ .12757	$ .16500

Comparison of Present and Proposed Rates

	Present Rates	Proposed Rates
Natural Gas Vehicles:		
Customer charge	$ 12.00	$ 15.00
Energy charge per therm	$ .14119	$ .17500
Small Commercial Transportation:		
Customer charge	$17.00	$25.00
Transportation charge per therm	$ .20259	$ .26549
Commercial Transportation:		
Customer charge	$50.00	$55.00
Transportation charge per therm	$ .16336	$ .19839
Interruptible Transportation:		
Customer charge	$ 175.00	$ 175.00
Transportation charge per therm	$ .12757	$ .16500
Contract – Interruptible Transportation:		
Customer charge	$ 175.00	$ 175.00
Transportation charge per therm	$ .12757	$ .16500

Comparison of Present and Proposed Rates

	Present Rates	Proposed Rates
Interruptible Large Volume-Transportation:		
Customer charge	$400.00	$400.00
Transportation charge per therm	$ .08252	$ .12000
Contract Interruptible Large Volume-Transportation:		
Customer charge	$400.00	$400.00
Transportation charge	$ .08252	$ .12000
Connect and Disconnect Charges:		
Residential	$ 20.00	$ 30.00
Non-residential	$ 45.00	$ 60.00
Change of Account Number:	$ 15.00	$ 20.00
Collection Charge:	$ 15.00	$ 15.00
Returned Check Charge	$ 15.00 or 5%	$ 25.00 or 5%