Florida Public Utilities Company
Minimum Filing Requirements
Before the Florida Public Service Commission
DOCKET NO.: 080366-GU
Volume I: Testimonies & Schedules A-C

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080366-GU

MINIMUM FILING REQUIREMENTS
DIRECT TESTIMONY AND EXHIBITS

December 2008

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
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MINIMUM FILING REQUIREMENTS
INDEX

TESTIMONY

DIRECT TESTIMONY
OF
CHERYL MARTIN,
IN

FLORIDA PUBLIC UTITITIES COMPANY
DOCKET NO 080366-GU

IN RE: PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY
FOR A NATURAL GAS RATE INCREASE

Q. Please state your name, affiliation, business address and summarize your academic background and professional experience.

A. My name is Cheryl Martin. I am the Controller for Florida Public Utilities Company (FPU), which has a business office at 401 South Dixie, West Palm Beach, Florida 33401. I have been employed by FPU since 1985 and performed numerous accounting functions until I was promoted to Corporate Accounting Manager in 1995 with responsibilities for managing the Corporate Accounting Department including regulatory accounting (Fuel, PGA, conservation, rate cases, Surveillance reports, reporting), tax accounting, external reports, and special projects. In January 2002 I was promoted to my current position of Controller where my responsibilities are the same as above with additional responsibilities in the purchasing and general accounting areas and Security and Exchange Commission (SEC) filings. I have been an expert witness for numerous proceedings before the Florida Public Service Commission (FPSC) including rate relief in Docket Numbers 881056-EI, 930400-EI, 030438-EI and 070304-EI for electric and 900151-GU, 940620-GU, 040216-GU for natural gas. I graduated from Florida State University in 1984 with a BS degree in Accounting. Also, I am a Certified Public Accountant in the state of Florida.

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

A. I supervised the overall preparation of the rate proceeding including the Minimum Filing Requirement (MFR) filing, and provided some of the accounting information that supports the proposed permanent and interim increases in revenue requirements for FPU for our Consolidated Natural Gas Division. April Lundgren, Jim Mesite, Doreen Cox and I were specifically responsible for the information provided in the MFR, Schedules A, B, C, F, and G. See testimony provided by April Lundgren, Jim Mesite and Doreen Cox to supplement support of these MFR schedules. Additional supporting information and testimony relating to these schedules has also been provided by the division General Manager of each area as well as the Marketing Director and Corporate Services Manager with details indicated in their testimony. See the testimony of Marc Schneidermann, Don Kitner, and Marc Seagrave for additional information. The cost of service, rate design, related testimony, and the MFR Schedules E, H and I, were supported and provided by Marc Schneidermann and Don Kitner. The cost of capital study, testimony and related schedules contained within MFR schedules D and G were prepared and supported by Robert Camfield and Doreen Cox.

Q. What is the revenue increase requested by FPU in this proceeding?

A. FPU is requesting a permanent increase in natural gas rates and charges in the amount of $9,917,690 in order to cover the deficiencies in revenues for the projected 2009 test year. This increase is necessary for FPU to have the opportunity to earn a fair rate of return on its investment. In accordance with Rule 25-7.140, F.A.C., Test Year Notification, we have notified the FPSC that we have selected the twelve-month period ending December 31, 2009, as the appropriate projected test year for our petition to increase our rates and charges. Our last increase for the Consolidated Natural Gas Division was filed in 2004.

Q. Why was a rate preceding necessary at this time?

A. The Company has experienced and is expecting to experience continued increases in expenses, and despite efforts to keep expenses down, many are beyond the control of the Company. We expect a significant decline in our rate of return in our natural gas operations. The Company believes the proposed 2009 test year will accurately reflect the economic conditions in which the Consolidated Natural Gas Division will be operating during the first twelve months the new rates will be in effect, and therefore this period is appropriate for rate setting purposes. We have had historical events that had a significant unfavorable impact to earnings since our last rate proceeding. We expect many costs to continue to increase; and for the most part, these costs are beyond our control. The Construction and Housing Industry is continuing to face an economic downtrend, affecting our ability to increase customers that historically have offset many of the normal increases to expenses. In addition, customers have been conserving energy and sales units continue to decline as a result of the overall economic conditions facing Florida and the entire Country. We anticipate this economic downtrend to continue for the next several years. We anticipate continued increases in our insurance, audit fees, and pension costs. The inflationary impacts on new and replacement utility plant as well as operating expenses contributed to our declining rate of return. We feel it is appropriate to seek a rate increase at this time to allow the Company the opportunity to earn a fair rate of return on our investment in utility plant and working capital. Earning a fair rate of return will enable us to continue our high quality of service and maintain financial integrity, which are in the best interest of our customers.

Q. How did you derive the projected revenue requirement for the 2009 test year?

A. The derivation of the revenue requirement and projected revenue deficiency is summarized on Schedule G-5 in the MFR. In summary, the 2009 revenue requirement is determined by multiplying the projected rate base by the required rate of return to arrive at the operating income required. This required operating income is then compared to the projected 2009 operating income using our existing billing rates and charges and projected rate base and operating expenses. Any deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required to realize a fair rate of return on rate base. This required increase amounts to an additional $9,917,690 in annual gas rates and charges. The required rate of return is 8.74% as is shown on Schedule G-3 (D-1) and A-5 in the MFR. The projected rate base is $73,747,220 and is shown on Schedule G-1 (B-2) and Schedule A-3 in the MFR.

Q. You are also requesting that the Commission grant interim relief. Why are you seeking Interim Rate Relief at this time?

A. Florida Public Utilities Company is seeking Interim Rate Relief because as of December 31, 2007 we are not earning a sufficient return on our investment to allow our shareholders the opportunity to earn a fair rate of return. Expenses have increased beyond our control, and the current trends in the housing markets and overall economy have presented further pressures that negatively impacted our earnings. We are below the low point of our allowable return and without rate relief are expected to continue to earn a return well below our allowable rate of return.

Q. How did you derive the revenue deficiency used in your Interim Rate Relief calculation?

A. The derivation of the 2007 revenue deficiency is summarized on Schedule F-7 in the MFR. In summary, the 2007 revenue requirement is determined by multiplying the 2007 rate base by the allowed rate of return as stated in Section 366.071(5)(b)(1) of the Florida Statutes to arrive at the operating income required. This required operating income is then compared to the 2007 actual operating income using our existing billing rates and charges and 2007 actual rate base and operating expenses. The deficiency in operating income is then expanded using the revenue expansion factor to arrive at the additional revenue required to realize a fair rate of return on rate base. This required interim increase amounts to an additional $984,054 in annual gas rates and charges. This increase stated in percentage terms is equal to 5.58% on base rates and charges. See Schedule F7 in the MFR for a computation of this increase. The required rate of return is 7.66% as is shown on Schedule F-8 in the MFR. The 2007 rate base is $59,518,973 and is provided in Schedule F-1 in the MFR.

Q. Is the required rate of return, or weighted average cost of capital, used in your Interim Rate Relief calculation equal to the weighted average cost of capital calculated for the 2007 Historic Year?

A. No. Section 366.071(5)(b)(1) of the Florida Statutes gives guidelines for granting Interim Rates. "'Required rate of return' shall be calculated as the weighted average cost of capital for the most recent 12-month period, using the last authorized rate of return on equity of the public utility, the current embedded cost of fixed-rate capital, the actual cost of short-term debt, the actual cost of variable-cost debt, and the actual cost of other sources of capital which were used in the last individual rate proceeding of the public utility." For the purpose of calculating Interim Rate Relief, we used a return on equity equal 10.25%. This is the low point of the previously allowed return on equity range.

See Schedule F8 in the MFR. See the panel testimony of Camfield and Cox for further details.

Q. Have you provided testimony to support some of the projection items and assumptions used in the projected test year 2009 income statement?

A. Yes, I have included those that I had direct responsibility to project in my testimony. I also provided assistance and support for additional items detailed in the testimony provided by others within this rate proceeding.

Q. What is the amount of rate case expense included in this rate proceeding?

A. We have included a total rate case expense of $844,080 to be amortized over a period of four years at $211,020 annually.

Q. Explain the period of time used for amortization of rate case expense and the amount included in rate base?

A. We have amortized our expected rate case expenses over a period of four years. Our last rate proceeding was four years ago. The expected period of time to file another rate proceeding is within that same period of time and four years is the appropriate number of years to amortize this expense. These expenses were necessary and prudent and we feel that recovery should be allowed over the expected period. The working capital includes the amount of unamortized rate case expense for 2009.

Q. What is the basis for the rate case regulatory expense included in the projected test year?

A. We have projected rate case expense based on specific forecasts including the cost to use consultants to assist us in preparation and support of a rate case and the cost for representation and consultation by an attorney. We are not staffed at a level to allow for preparation of rate proceedings, MFRs or the additional rate case related work load required after the MFRs are filed. Internally our work load has increased since our last gas rate case was filed without an offsetting increase in staff or expertise within the Company, and we now require additional resources beyond the level required in our last gas rate case. We do not have the expertise in all areas to help facilitate the preparation of a rate case; therefore we had to hire the expertise and extra assistance to complete this process. We also had to utilize temporary accounting staff and consultants to assist in the extra rate case work beyond the normal work load of the accounting department. See Schedule G-2 (C-13) in the MFR for more details on these expenses.

Q. How does the company allocate costs for corporate charges across the different utility services?

A. The Company allocates costs for corporate charges across the different utility services on a consistent basis. The allocation methods vary by account, but we use allocation factors based on number of customers, base revenues, plant in service, and time studies to allocate the various charges as appropriate. At the local level, when there are multiple utilities, the Company applies these same methods but at the divisional level. The supporting documentation for these allocations can be found in MFR Schedule G-6. Due to the timing of the filing, 2008 allocations were used for 2009 projections.

Q. Why is it appropriate to allow recovery for all expected pension and insurance expenses?

A. Pension costs are similar to salaries and wages; it is a necessary cost to operate a utility function. We only provide prudent wages and benefits to our employees, and accordingly, all costs are appropriate for recovery including the pension costs. The pension plan assets have been prudently invested, and provide for a return on the assets. All costs are necessary and should be allowed for recovery in our base rates. Insurance costs included in our expenses are a necessary and prudent expenditure and should be allowed and are appropriate for recovery in base rates. Insurance is a prudent cost to help a company manage risk associated with operating a business. Medical Insurance is a necessary benefit to our employees, and the costs are appropriate for recovery.

Q. Is it appropriate to include the FASB 158 portion allocated to natural gas in Working Capital?

A. Yes, the impact to Other Comprehensive Income (OCI) from the implementation of FASB 158 has been deferred as a regulatory asset/liability for retirement plans. This regulatory asset/liability will be deferred until it is recognized as current pension expense. It is appropriate for both this regulatory asset/liability and the pension liability be included in working capital.

Q. Did the Company properly adjust the payroll expenses allocated to natural gas as an over and above adjustment to correct for a prior allocation error?

A. Yes, the Company previously allocated the incorrect amount of payroll to their nonregulated operations based on customer counts and time studies. The customer counts were overstated due to errors in the computation and methodology of determining who is a customer.

In both 2007 and 2008 allocations, immaterial value added services/warranty programs sold to natural gas customers were duplicated and counted as merchandise and jobbing customers. If we do sell merchandise or related jobbing services to natural gas customers or to any type of customer, we properly count them as a merchandise and jobbing customer. The warranty type services should not be considered as a separate customer.

The time studies were based on historical studies that did not take into account the current economic decline in our economy, and the dramatic slowdown in the housing and construction industry beginning in late 2007. Our Merchandise and jobbing activity year to date September 2008 dropped significantly, and the amount of time required to service these types of customers and issues has also dropped over periods that the studies used to allocate were based upon. This reduced levels of merchandise and jobbing activity is expected to continue over the next several years, and is most appropriate to use in our 2009 test year. The allocations were not adjusted before 2008 began to account for this significantly reduced level of activity that is expected to continue over the next several years.

To correct for this customer count error and time studies used in payroll allocations, we increased the expenses allocated to natural gas in 2008 by an estimated $100,000 and projected this amount for our projected test year as well since these conditions are expected to continue through 2009 and beyond. It is primarily for payroll that is allocated based on customer counts and time studies. The details and actual amount of this adjustment will be recorded on our books late 2008 and can be provided as support upon request. Allocations will be updated before January 2009 for calendar year 2009.

Q. Does this allocation error have an impact on any other item within the filing?

A. Yes, the nonregulated allocations in plant should be updated for 2009 to account for this correction in customer counts once the data has been finalized. This will occur before the end of 2008 but was not done in time to incorporate into our MFR filing. We are able to provide this information upon request.

Q. How did the Company project the income tax expense?

A. The Company used the historical timing differences to estimate the timing differences for the projected test year 2009 and projected year 2008. Projected net income before income taxes and interest expense, less the interest calculated on our cost of capital projections, adjusted for the expected timing differences, was multiplied by the effective tax rate. This provided total current tax expense. The timing differences times the effective tax rate provided the deferred tax expense. The Company uses an effective tax rate of 37.63% which includes both federal and state tax rates. All adjustments made to the income statement were also considered for income tax adjustment purposes. The income tax effective tax rate for projected tax years, 2008 and 2009 is 37.63%.

The only change to the overall effective tax rate is the ITC amortization. This projection was based on the actual ITC amortization schedules and slightly reduces the overall effective tax rate.

The MFR schedules provide the details of our tax projections, timing differences and other related tax computations.

Q. Are the projections for administrative salaries appropriate as projected by the Company?

A. Yes. The Company has included a projected salary increase for the administrative personnel, by each individual personnel. We have utilized estimates by our HR director, for the total expected increases in 2009, and estimates for our executives based on historical trends. All salaries are either below current market rates or within appropriate market rates. Recent salary surveys have been completed and support our claims with respect to appropriate salary levels for administrative personnel as well as all Company employees. Our projections are appropriate as filed in the MFRs and are both reasonable and prudent. See April Lundgren's testimony for additional information relating to administrative salary projections.

Q. Have you proposed a special base rate increase outside of this current MFR filing and revenue request, for recovery of an extraordinary capital expenditure to be completed in late 2010?

A. Yes, see testimony and exhibits provided by witness Jim Mesite and witness Marc Schneidermann for details. We are requesting that the Commission consider granting special rate relief to be effective after our current rate proceeding relief, for recovery of a needed operations center in our natural gas segment. We have offered two alternatives for consideration that will allow our Company to receive rate relief for this large capital expenditure, and at the same time it will provide our customers with the most economical method for the Company to obtain this type of needed special recovery.

Q. Please summarize your testimony.

A. FPU is requesting a permanent increase in the natural gas rates and charges in the amount of $9,917,690 in order to cover the deficiencies in revenues for the projected 2009 test year. This required revenue is based on a rate of return equal to 8.74% and a 2009-projected rate base of $73,747,220.

Florida Public Utilities Company is also requesting interim rate relief in the amount of $984,054 in annual gas rates and charges. Stated in percentage terms, we seek an interim increase in revenues equal to 5.58% on base rates and charges. The interim rate increase is based on a weighted average cost of capital equal to 7.66% and a 2007 rate base of $59,518,973.

Q. Is the Projected test year 2009 as filed in your MFR filing appropriate for use in determining and setting base rates?

A. Yes, the Company has appropriately projected the 2009 test year and this year is reflective of the period that the final rates will become effective.

Q. Does this conclude your written prepared testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION OF

FLORIDA PUBLIC UTILITIES COMPANY

FOR A NATURAL GAS RATE INCREASE

DOCKET NO 080366-GU

DIRECT TESTIMONY AND EXHIBITS

OF

JAMES V. MESITE, JR.

Q. **Please state your name, affiliation, business address and summarize your academic background and professional experience.**

A. My name is James V. Mesite, Jr. I am the Senior Project Accountant in the Corporate Accounting Department at Florida Public Utilities Company (FPUC or Company). My business address is 401 South Dixie Highway, West Palm Beach, Florida 33401. I am a graduate of Northeastern University, class of 1976, with a Bachelor of Science degree in Business Administration, major in Accounting.

I have been employed by FPUC for 13 years. I began my tenure as a Special Project Accountant and was promoted to my current position in March 2002. In the past I was responsible for converting the Company's manual CPR records to a computerized system; and I continue to be responsible for the overall integrity of the computerized

Fixed Asset System. I am responsible for the review and evaluation of fixed asset issues involving acquisitions, dispositions, retirements, capital versus expense, and chart of accounts. I assist in the preparation of annual corporate budgets, and various aspects of the inventory processes. I have designed and implemented several procedures and reporting systems for accounting and auditing purposes. I prepare several periodic accounting analysis reports using various company systems and computer applications. Additionally, I am involved with various internal control and review projects throughout the Company as circumstances dictate.

I am responsible for the filing of Depreciation Studies with the Florida Public Service Commission (Commission or FPSC) for the regulated electric and natural gas divisions. At various times I have been responsible for preparation, filing, reconciliation and audit of documents as directed under PGA Docket Nos. nn0003-GU, and electric fuel Docket Nos. nn0001-EI. I have been a witness in three previous rate relief proceedings before the FPSC: Docket Numbers 030438-EI, 040216-GU, and 070304-EI. I have participated in FPSC Natural Gas and Electric workshops and inquiries relating to Listing of Retirement Units and capitalization threshold.

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

A. I will assist in providing accounting information that supports the proposed increase in revenue requirements for FPUC. I am witness on information provided in various MFR Schedules B, C, F, and G.

Q. **In what are the major areas of the MFR are you a witness?**

A. I am witness in the areas of Plant and Working Capital for the determination of Rate Base. I am also witness for amortization expense and depreciation expense and associated adjustments for the determination of NOI.

BALANCE SHEET

PLANT ACCOUNTS

Q. What methods were used to project 2008 Plant account monthly balances?

A. For all utility plant accounts and the Common plant accounts, actual account balances were used through April 2008. For May through December 2008, plant accounts were projected based on total expenditure levels according to the 2008 annual budget forecasts adjusted for the actual expenditures through April.

The 2008 FPUC capital budgets were developed during the latter half of the previous year, using targeted spending levels for the various segments as determined by FPUC management based on historical expenditure levels and other anticipated requirements. Division Managers and department heads then determined the allocation of the targeted levels for capital budgeting purposes based on their individual division's or department's capital requirements and other specific needs. As special circumstances dictate, from time to time it is necessary to redefine the expenditures of remaining budget funds. The 2008 budget information as of May 1, 2008, was used for projecting the remaining 2008 expenditures.

Q. What methods were used to project 2009 Plant account monthly balances?

A. Division Managers determined anticipated requirements based on their historical needs and other additional known and anticipated needs specific to their divisions. For Common plant accounts, department heads determined requirements based on their assessment of requirements specific to their departments.

In addition to projecting the typical capital spending levels, the Bare Steel and Tubing Replacement Program has been expanded. This program is discussed later in my testimony and in the testimony of Mr. Donald E. Kitner.

Q. In addition to the typical historical items, what are major items that are included

in the 2009 Budget.

A. Included in the 2009 Budget are expenditures for increased expenditures for the Bare Steel and Tubing Replacement Program, expenditures for the design and site plan approval for the South Florida Operation Center, for an expansion project into western Palm Beach County, and for various transportation and construction equipment.

Q. Please discuss the Bare Steel and Tubing Replacement Program.

A. Included in the 2009 Budget, are expenditures of $623,106 for our Bare Steel and Tubing Replacement Program. During our previous 2004 Natural Gas rate proceeding, the Commission approved annual recovery of $566,308 over 50 years for expenditures to replace aging bare steel mains and services. For this proceeding we are modifying the program to include aging steel tubing, and extending the recovery period to 60 years, which results in an annual recovery of $623,106.

Q. What are the circumstances surrounding the expenditures for the design and site plan approval for the South Florida Operations Center?

A. Included in the FPUC Construction Budgets, is $66,800 in 2008, $133,200 in 2009 for expenditures for the design and site plan approval for a new South Florida Operations Center. The South Florida natural gas segment has been, and is, in need of a larger operations center.

There are outstanding environmental issues with the existing property that are in the process of being resolved. In order to proceed with the environmental mitigation, FPUC must vacate the current property. Plans are currently underway to construct a facility and move the South Florida Operations Center to the new location by November 2010.

Please see the direct testimony of Mr. Marc L. Schneidermann for a discussion of the new South Florida Operations Center.

Q. Is recovery for the new South Florida Operations Center included in this rate

proceeding?

A. No, we are not filing for recovery as part of this proceeding. However, due to the immanent impact of the large expenditures for operation center construction, we are requesting that the Commission consider granting special future rate relief. We are proposing two alternatives for consideration during this proceeding, that will provide rate relief without the need for a separate costly and time consuming full rate proceeding.

The first alternative for consideration, and the one that is the most cost effective, would be to calculate base rates using the data as presented in this MFR. Concurrently, the Commission would approve a flat percentage increase that is to be added to energy charges for base rates, once the operations center is completed. This additional base rate percentage would be calculated to cover the additional effect on base rates resulting from the changes in rate base and NOI resulting from the completion of the operations center. Exhibit JVM-5 details the computation of the proposed add-on base rate percentage increase of 4.036%, using currently available information as contained in the MFR. Various components and the final rate increase used for the exhibit's calculation will require updating once their final values are determined within this rate case procedure. This rate increase would become effective upon completion of the operations center. The expected date of completion is November 2010.

Our second proposed alternative would be for the Commission to allow FPUC to conduct a limited proceeding at the conclusion of the operation center construction. The limited proceeding would adjust base rates upward for the effects on rate base and NOI specifically relating to the construction costs and incremental cost increases associated with the new operation center, and the cost of the limited proceeding. While this alternative would still require additional costs for a limited proceeding, these cost would be much less than required for a normal rate proceeding.

Future additional costs to complete the South Florida Operations Center are estimated to be $4,800,000. Please see the testimony of Mr. Schneidermann for additional details on this issue.

Q. What is the expected cost to FPUC for the western Palm Beach County expansion project?

A. After application of expected AEP contributions, the installation of mains associated with this project is expected to be $358,039. Mr. Kitner describes this project in further detail in his direct testimony.

Q. What is the cost and the makeup of the transportation and construction equipment included in the 2009 Budget?

A. These items are budgeted for $200,500. Included are three pickup trucks, one dump-truck, a forklift for the warehouse operation, and a backhoe. All items are needed for operations.

Q. What methods were used to allocate Common Plant accounts?

A. All Common plant accounts, except Computer Equipment and Software, were allocated based on the utility's share of non-Common, total consolidated plant (exclusive of Computer Equipment and Software). Common's Computer Equipment and Software accounts were allocated to the natural gas utility based on the utility's share of FPUC's total consolidated customers.

For 2007, the allocations were those used to allocate the books and records of the Company during the year 2007. For 2008, the allocations are the ones currently being used to allocate the books and records of the Company for the year 2008. For 2009, the 2008 allocations were also used since those allocations are based on the most currently available information. The allocations should be updated once they are complete. We can provide this data upon request. The 2007 and 2008 common plant allocations used for the filing are provided in Schedule G-6, Page 4.

WORKING CAPITAL ACCOUNTS

Q. What methods were used to project the Projected Year 2008 Working Capital accounts?

A. The 2008 13-month averages for working capital accounts were projected using a variety of methods. Information concerning the projection methods applied to individual accounts is contained on Schedule G-1, Pages 5B and 6B, in columns (5), (6), and (12). Actual monthly utility balances for January 2008 through April 2008 were used. The projected May 2008 through December 2008 balances represent the 2008 utility 13-month average projected balance adjusted for the actual January 2008 through April 2008 activity.

Many accounts were projected using appropriate projection factors for inflation, payroll, customer growth, or unit growth. Schedule G-6, Page 3, contains a listing of these projection factors. The results produced by applying appropriate factors produced reasonable expected projections.

Several accounts were directly projected using historical data or other appropriate methods. The details of these projections are shown in Schedule G-1, Pages 5B and 6B, in column (12), and/or detailed later in my testimony.

Q. What methods were used to project the Projected Test Year 2009 Working Capital accounts?

A. The 2009 13-month averages for working capital accounts were projected using a variety of methods. Information concerning the projection methods applied to the individual accounts is contained on Schedule G-1, Pages 7B and 8B, in columns (5), (6), and (12).

Many accounts were projected using appropriate projection factors for inflation, payroll, customer growth, or unit growth. Schedule G-6, Page 3, contains a listing of these projection factors. The results produced by applying appropriate factors produced reasonable expected projections.

Several accounts were directly projected using historical data or other appropriate methods. The details of these projections are shown in Schedule G-1, Pages 7B and 8B, in column (12), and/or contained later in my testimony.

Q. Will you be detailing accounts that indicate that they were projected using direct projections?

A. Yes, many direct projections were based on appropriate projection criteria and are noted in Schedule G-1, Pages 5B, 6B 7B and 8B, in column (12). Such methods might include - no change to the account from the amounts shown for prior year, the account is equal to zero, and the account changed by the same historical activity every month as indicated.

Accounts that were projected using another method outside of those listed above contain notations that an explanation is contained in testimony. The details of these projected accounts are contained elsewhere in my direct testimony.

Q. What methods were used to allocate Working Capital accounts for Historic Year 2007, Projected Year 2008, and Projected Test Year 2009?

A. The allocation method and percentage of allocation to the utility for each working capital account is indicated on the various balance sheet schedules. For 2007, Schedule B-1, Pages 2 and 4, column 7 and column 8 contain the information. For 2008 and 2009, Schedules G-1, Pages 5B, 6B, 7B, and 8B, column 9 and 10 contain the appropriate information.

Generally, all working capital accounts were allocated based on Adjusted Gross Profit, Payroll, or Total Plant. A "Direct" allocation basis signifies that the account is maintained as a direct account of the utility and is allocated to the utility at 100%. Accounts that are allocated using other bases will be discussed individually and in detail later in my testimony.

Schedule G-6, Page 4 and 5 contains the details of the various allocations that were employed.

Q. **Please discuss direct projections for Cash, accounts 1310 and 1350 for 2008 and 2009.**

A. Cash balances are maintained that cover day to day operations and various ongoing fiscal obligations, at levels that allow for the routine swings between collections and expenditures. FPUC has continually demonstrated responsible cash management practices and processes in order to maintain minimum cash, at adequate and necessary levels. The amounts included for the cash account are based on cash flow projections which were developed for cost of capital and Company budgets. Refer to the Direct Testimony of Doreen Cox for details concerning the methods and criteria that were used when projecting cash.

In calculating projected "cash", total consolidated cash was the consideration, and as such the calculation included various divisional local operating cash and petty cash accounts included in accounts 1310 and 1350. These accounts and other adjustments are non-regulated and/or specific to operating segments and contained non-changing balances. It was necessary to remove the amounts from the projected consolidated cash amount prior to allocating the remaining consolidated cash to the utility. Exhibit JVM-1 details the derivation of consolidated cash to be allocated to utility cash for 2008 and

2009, as account 1310.

The utility specific local operating and petty cash accounts are included separately on the balance sheet as accounts 1350.

Q. How did you arrive at the projected 13-month average for Accounts Receivable-Customers, account 1420, for Projected Year 2008 and Projected Test Year 2009?

A. The monthly Accounts Receivable balances are a direct result of the projections in revenues and bill payments for the periods involved. We do not anticipate any major changes in bill payments other than a slowing of payments due to the ongoing slow-down in economic conditions and a corresponding increase in accounts written-off.

The revenue projections for calendar years 2008 and 2009 are being affected primarily by changes in PGA (fuel) costs, base rates and therm sales. Over 50% of our revenues consist of PGA costs. These costs have increased and are expected to continue to increase, both as a percentage of total revenues, and in per-therm unit cost. The average PGA rate used in 2007 was $0.72 per therm and 2008 and 2009 are projected to average $1.44 and $1.58 respectively. As a result of this rate proceeding, base rates were conservatively estimated to increase 20% in 2009. Therms sold per customer are expected to decrease 4% in 2008 and another 2% in 2009 due to the higher PGA, base rate increases, and slowing economy. Irrespective of the therm usage reductions, the combined net changes outlined above have resulted in a significant increase in sales revenues of 42% in 2008 and another 10% in 2009 and a corresponding increase in Customer Accounts Receivable for the years 2008 and 2009.

Q. **How did you arrive at the projected 13-month average for Allowance for Uncollectable, account 1440, for Projected Year 2008 and Projected Test Year 2009?**

A. The annual accruals for bad debts (Bad Debt Expense, Account 904) and the net write-offs will affect the 13-month averages. The Company has projected the annual Bad Debt Expense to be $270,000 in 2008, and $639,000 in 2009. These estimates are explained in the testimony pertaining to NOI of Ms. April Lundgren.

The net write-offs are estimated to be $320,000 in 2008 and $550,000 in the projected test year 2009. The large increase in write-offs for 2009, are because of the increase in PGA driven typical bills and the current downturn in economic conditions as explained in Ms. Lundgren's testimony.

The Company also attempts to hold the Accumulated Provision for Bad Debts balance within a range of 3-5 months of current annual net write-offs. This would provide an acceptable provision balance of $140,000 to $230,000. Occasionally, we have had to hold additional reserves for resolution of pending bankruptcies. We have also shown month-to-month fluctuations in the accumulated balances to reflect seasonal fluctuations in billing and write-offs.

Q. What methodology was used to project Prepaid Insurance, account 1650.2 and account 1650.5 for 2008 and 2009?

A. Account 1650.2 is Prepaid Liability Insurance. For 2008, this account was projected using the inflation and customer growth factors applied to the September 2007 invoice. The account was then amortized at $1/12^{th}$ per month beginning with September 2008. For 2009, the account was projected using the inflation and customer growth factors applied to the projected September 2008 invoice amount. The account was then amortized at $1/12^{th}$ per month beginning with September 2009.

Account 1650.5 is Prepaid Workmen's Compensation Insurance. For 2008 the account is projected based on a quote received from the vendor for a forthcoming September 2008 invoicing which was amortized at $1/12^{th}$ per month beginning with September 2008. The vendor also provided a estimated amount for September 2009 which was amortized at 1/12th per month beginning with September 2009.

Q. Please describe the makeup of Regulatory Asset – Retirement Plan, account 1820.2.

A. This account represents the regulatory asset associated with pensions, retiree medical, and FASB 158 as it pertains to the regulated utilities. Final Order No. PSC-08-0210-CO-PU, under Docket No. 080029-PU, allows FPUC to defer these costs.

Q. What methodology was used for Projected Year 2008 and Projected Test Year 2009 to project Regulatory Asset – Retirement Plan, account 1820.2?

A. This account was projected for the remainder of 2008 and throughout 2009 by applying the payroll projection factor to the prior month's balance, and adding 1/12th of the resulting increase to the prior month's balance.

Q. What basis was used for allocating Regulatory Asset – Retirement Plan, account 1820.2?

A. As explained above, this account is associated with only activity in FPUC's regulated utility segments. As such, the account is allocated amongst FPUC's Regulated Natural Gas and Electric Utilities. Due to the nature of the account it is allocated based on the relative gross payrolls of only the regulated segments. Schedule G-6, Page 5 details the basis for the regulated payroll allocations used for the projections.

Q. Please discuss the source of the monthly balances presented for Deferred Rate Case Expense, Account 1860.1 for Projected Year 2008 and Projected Test Year 2009.

A. Details for the amounts presented for this account are contained in MFR Schedule G-2(C-13) and testimony of Ms. Cheryl Martin

Q. What is the basis for the projection used for Deferred Debits-Natural Gas, Account 1860.1 for Historic Year 2007, Projected Year 2008, and Projected Test

Year 2009?

A. The data presented for this account for the Historic Year 2007 and for January through April 2008, were for the consolidated natural gas division, derived via an item by item analysis of the monthly activity in the FPUC consolidated deferred debits account. Data for subsequent months was projected based on the natural gas actual historic data increased for the combined inflation and customer growth projection factors. Schedule G-6, Page 3 details the projection factors used.

Q. What is the basis for the projections used for Gas Storm Reserve, Account 2280.12 for Projected Year 2008 and Projected Test Year 2009?

A. Details for the amounts presented for this account are contained in the NOI direct testimony and exhibits of Ms. April Lundgren.

Q. What is the basis for the projections used for Medical – Post Retirement, Account 2280.32 for Projected Year 2008 and Projected Test Year 2009?

A. This account was projected based on estimates provided by the vendor. For 2008 the estimated increase is 11.4%, and for 2009 the estimated increase is 15%.

Q. What is the basis for the projections used for Accrued Property Taxes, Account 2360.1 for Projected Year 2008 and Projected Test Year 2009?

A. This account is carried as an FPUC consolidated account. All data within the account is maintained and reconciled based on individual property locations. The amounts allocated to the utility are representative of the property taxes specific to the property contained in the utility's plant accounts. 2008 and 2009 projections were arrived at by applying the projection factor for inflation to the previous year's utility 13-month average balance. Schedule G-6, Page 3 details the projection factors used.

<u>CAPITAL STRUCTURE ACCOUNTS</u>

Q. What is the basis for projecting capital structure accounts for Historic Year 2007, for Projected Year 2008, and Projected Test Year 2009?

A. Please refer to the Direct Testimony of Doreen Cox and Robert Camfield for details concerning the projection of the equity and debt accounts.

Q. What is the basis for allocating capital structure accounts on the Balance Sheet for Historic Year 2007, for Projected Year 2008, and Projected Test Year 2009?

A. There are two methods for allocating the capital structure accounts. The first method is the direct allocation of 100% of the account balance. This method is used where the account has been maintained or projected exclusively for the utility, and therefore no allocation is required. This method applies to Deferred Taxes, accounts 1900 and 28nn; Customer Deposits, account 2350.1; and ITC, account 2550.

The second method is allocation based on the remaining capital deficiency of the utility's balance sheet.

Q. What does this capital deficiency represent?

A. Once all of the plant, working capital, and direct capital structure account balances have been determined, the balance sheet is out of balance by a remaining capital deficiency. This capital deficiency represents the natural gas portion of the consolidated non-direct capital structure accounts – Common Equity, Preferred Stock, Long-term Debt and Short-term Debt accounts.

Q. How is the capital deficiency that is applicable to the utility's balance sheet calculated?

A. For the non-direct capital structure components – Common Equity, Preferred Stock, Long-term Debt and Short-term Debt - the consolidated ratio for each component is applied to the natural gas capital deficiency. The resultant share for each component is then used to complete the natural gas balance sheet.

RATE BASE ADJUSTMENTS

COMMISSION RATE BASE ADJUSTMENTS

Q. What is the basis for including the various Commission Adjustments when computing rate base?

A. Commission adjustments are those adjustments required by the FPSC in prior rulings and as a result of the final order of the previous natural gas rate case: Docket No. 040216-GU, Order No. PSC-04-1110-PAA-GU.

Q. Please list the Commission Adjustments to Rate Base that have been included in the MFR for Historic Year 2007, Projected Year 2008, and Projected Test Year 2009.

A. Commission adjustments to rate base are:

- reductions to plant and plant reserve accounts for the portion shared with non-regulated business segments;
- elimination of a non-compete agreement;
- elimination of goodwill;
- unrecorded goodwill reserve;
- reductions to materials and supplies inventory for the portion shared with non-regulated propane operations;
- elimination of the unamortized AEP deferred debit account;
- and elimination of one-half of the deferred rate case expense.

Q. How are the adjustment amounts for plant and plant reserve accounts determined?

A. Each year the individual plant accounts are reviewed to determine their usage between regulated natural gas and non-regulated operations. Based on customers, the non-regulated usage portion is then adjusted out of the plant and the plant reserve accounts. The details of these adjustments are contained in Schedule B-3 and Schedule G-1(4B). For 2009, the 2008 allocations were used since the new rates were not completed. The Commission should adjust these for the latest allocations. These will be made available upon request.

Q. Why are the non-compete agreement and goodwill eliminated from rate base?

A. The Commission has determined in prior rate cases that both of these accounts are not to be included in rate base.

Q. What are the circumstances surrounding the adjustment for unrecorded goodwill reserve?

A. During our previous rate case it was determined that FPUC had not begun to record the monthly amortization of approved goodwill at the appropriate time. As detailed in the final order, this adjusting entry is to adjust the goodwill reserve balance to what it would be had the correct amortization been recorded.

Q. What is the basis for the adjustment to materials and supplies inventory?

A. During the previous rate case, the Commission determined that 9% of the materials and supplies inventory account is for the benefit of FPUC's non-regulated propane operations.

Q. Please discuss the adjustment to eliminate the account for deferred AEP Costs.

A. Contained in the order authorizing our AEP program was a declaration that the deferral account was to be excluded from rate base.

Q. Please discuss the adjustment to eliminate one-half of the Deferred Rate Case account.

A. The Commission has ordered that one-half of the deferred rate case expense be eliminated from rate base.

COMPANY RATE BASE ADJUSTMENTS PROJECTED TEST YEAR (2009)

Q. Briefly describe the Company adjustments to rate base for the projected test year 2009, that are included in the MFR. Also, please indicate the Adjustment Number from Schedule G-1(4A) that is assigned to each adjustment.

A. Company adjustments to rate base include:

- A modification to the amortization amount of the Bare Steel Replacement Program; Adjustment 3.
- An adjustment to plant for the Area Expansion Program (AEP) contribution deficiency; Adjustment 4.
- Adjustments to reflect the effect to plant reserve account balances for the above proposed adjustments to plant; Adjustments 7 and 8.

Q. The Bare Steel Replacement Program was approved by the Commission in FPUC's 2004 rate case. What are the circumstances that require a modification to the amortization amounts approved in that rate case?

A. We have added steel tubing to our bare steel replacement program that was previously approved in our prior rate case. Additionally, significant material and installation cost increases have inflated the expected cost of the bare steel portion of the program. The amortization period of the program has been extended from 50 years to 60 years.

Specific details regarding modification to this program are presented in the direct testimony of Mr. Donald E. Kitner.

Q. What are the anticipated projected test year 2009 rate base effects of these proposed changes to the Bare Steel & Tubing Replacement Program?

The anticipated completion costs of this program are expected to be $37,386,365. We propose that this amount be recovered over the next 60 years, for a total annual recovery of $623,106. The annual recovery for this program that was approved in our prior 2004 rate case was $566,308. We are requesting an additional annual recovery of $56,798.

This proposed adjustment to the Bare Steel & Tubing Replacement Program will reduce rate base by $27,975. The increased annual recovery reduces plant by $28,399, with a resulting decrease to plant reserve of $424, and a increase to amortization expense of $56,798.

Please refer to Exhibits JVM-2 and JVM-3 for details concerning the calculation of this rate base adjustment.

Q. What precipitated a need for the proposed adjustment for recovery of unrecovered AEP contributions?

A. Our Area Expansion Program (AEP) was approved in a separate docket in 1995 and FPUC currently maintains 44 active AEP projects. Due to the downturn in the economic climate over the past several years, particularly in the housing development market, it has become apparent that several of these AEP projects will produce shortfalls in the recovery of the costs currently being recovered via the AEP surcharge on natural gas consumption.

Please refer to the direct testimony of Mr. Marc S. Seagrave for a detailed explanation of this AEP recovery issue.

Q. How does FPUC propose to deal with these imminent unrecoverable AEP contributions?

A. As detailed in Mr. Seagrave's testimony, FPUC proposes to manage the shortfall on two fronts. First, we are proposing an increase in the allowable surcharge rate. Second, any remaining expected shortfall is included in plant and in rate base as a reduction in expected contributions.

Q. What are the effects of this adjustment on the projected test year 2009 rate base?

A. The estimated unrecoverable AEP contributions, after taking into account the proposed AEP surcharge rate increase, is $2,461,202. This amount is added to plant and increases rate base by $2,461,202. The associated increase to reserve is $31,998, resulting in a net increase to 2009 rate base of $2,429,204.

Please refer to Exhibit JVM-4 for details concerning the calculation of this rate base adjustment. See my direct testimony pertaining to Company NOI adjustments for testimony regarding associated NOI effects of this adjustment.

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Q. Has FPUC filed a depreciation study in conjunction with this rate proceeding?

A. Yes. We have filed a depreciation study under Docket No. 080548-GU. For the depreciation study we are requesting an implementation date to coincide with the date the base rates will become effective: this date is expected to be early 2009.

Q. Is FPUC including an adjustment to rate base for the results of the depreciation study?

A. No. Since the results of the depreciation study will not be available until after this rate proceeding is filed, we are not including an adjustment. However, once the depreciation study is finalized, we anticipate that final rate relief will include a true-up to rate base and depreciation expense for the 12-month effect of applying the depreciation study results.

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<u>NET OPERATING INCOME - NOI</u>

COMMISSION NOI ADJUSTMENTS

Q. Please specify the categories of Commission Net Operating Income (NOI) adjustments will that you will provide testimony to support, and what are the years covered by the testimony?

A. I provided testimony on the Commission NOI adjustments relating to depreciation and amortization expenses. The Commission adjustments were applicable to Historic Year 2007, Projected Year 2008, and Projected Test Year 2009.

Q. Please discuss the Commission NOI adjustments for amortization.

A. There is a single Commission adjustment for amortization expense. This adjustment eliminates the total amount charged as AEP amortization expense. Due to the nature of the AEP program, the Commission has ordered that AEP expenses and revenues be eliminated from the computation of NOI.

Q. Please discuss the Commission NOI adjustments for depreciation.

A. When computing NOI, there is a single Commission adjustment for depreciation expense. This adjustment eliminates an amount of depreciation attributable to plant accounts maintained by the regulated natural gas divisions that are shared with non-regulated FPUC business segments. As detailed in my testimony on Commission rate base adjustments, each plant account is analyzed annually and a determination is made of the percentage that is shared. Based on that analysis, that same percentage of non-regulated depreciation expense is removed from the NOI calculation as a Commission adjustment.

2009 COMPANY NOI ADJUSTMENTS

Q. For which categories of Net Operating Income (NOI) Company adjustments were you responsible?

A. I provided Company NOI adjustments relating to depreciation and amortization expenses.

Q. Briefly describe the Company NOI adjustments for the projected test year 2009 that were presented in Schedule G-2(C-2)(2009), for which you were responsible.

A. Company NOI adjustments were:

1.) Decrease in NOI for proposed increase in the amortization for the Bare Steel & Tubing Replacement Program;

2.) Increase in NOI for the decrease in depreciation expense resulting from the proposed increase in amortization for the Bare Steel & Tubing Replacement Program;

3.) Decrease in NOI for increases in depreciation expense resulting from adjustment in AEP contributions;

Q. Describe the NOI adjustment relating to the increased amortization for the Bare Steel & Tubing Replacement Project.

A. As detailed in my earlier testimony concerning the 2009 Company rate base adjustments, FPUC is proposing an increase in the annual amortization under its Bare Steel &Tubing Replacement Program. The annual increase in amortization that is being requested is $56,798. See Exhibit JVM-2 and JVM-3 for details concerning this NOI adjustment.

Q. Describe the adjustment to increase NOI for decreases in depreciation expense resulting from the increased amortization for the Bare Steel & Tubing Replacement Program.

A. The increase to the amortization of the Bare Steel & Tubing Replacement Program, as described in the 2009 Company rate base adjustments portion of my direct testimony, will result in a reduction to utility plant. This adjustment represents a $1,166 decrease in depreciation expense resulting from the decrease in plant. See Exhibit JVM-2 and JVM-3 for details concerning this NOI adjustment.

Q. **Describe the adjustment to reduce NOI for increases in depreciation expense resulting from the adjustment of AEP contributions.**

A. Earlier in my direct testimony for adjustments to 2009 rate base, I described where FPUC proposes an adjustment for future expected unrecovered AEP contributions against plant. This NOI adjustment of $63,996 increases depreciation expense due to the effect of reversing the contributions. See Exhibit JVM-4 for details concerning the calculation of this NOI adjustment.

DEPRECIATION EXPENSE

Q. **Please describe how depreciation expense for Projected Test Year 2009 was determined**

A. Schedule G-2(C-17)(2009) indicates depreciation expense by plant sub-account. The depreciation expenses are based on depreciation rates established in Docket No. 040352-GU, Order No.: PSC-04-1045-PAA-GU. We anticipate that this depreciation expense will require a true-up to reflect the 12-month effects for our Consolidated Natural Gas division depreciation study, Docket No. 080548-GU that has been filed and is currently under review by the FPSC.

2009 PAYROLL OVERHEAD RATES

Q. **Why are Payroll Overhead Rates required?**

A. In instances where payroll costs were increased or projected based on a per hour rate or salary level, it is necessary to further increase these payroll base costs by a factor to reflect the associated additional direct costs for payroll taxes, insurances and company benefits. These overhead rates were calculated based on the 2007 actual overhead cost as a percentage of payroll dollars. Separate overhead rates were calculated for the South Florida and Central Florida natural gas operating segments.

Q. How were the overhead rates applied?

A. The appropriate overhead rate was applied based on the natural gas segment incurring the payroll costs. For the South Florida natural gas segment the applied rate was 30%. For the Central Florida natural gas segment the applied rate was 31%.

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Q. Does this conclude your testimony?

A. Yes.

EXHIBIT JVM-1
FLORIDA PUBLIC UTILITIES COMPANY
080366-GU

FLORIDA PUBLIC UTILITIES COMPANY
2008 and 2009 CASH PROJECTION
BUDGET

2008 CASH	DEC. '07	JAN. '08	FEB. '08	MAR. '08	APR. '08	MAY. '08	JUN. '08	JUL. '08	AUG. '08	SEP. '08	OCT. '08	NOV. '08	DEC. '08	13-month avg
Total Consolidated Cash	3,477,649	(89,778)	(1,125,637)	2,520,909	1,146,116	1,605,239	2,492,387	738,130	1,720,836	386,329	281,654	468,279	352,495	1,074,970
Less:														
Ppd Dividends 2380	688,174	-	-	690,177	-	-	721,506	-	-	-	-	-	-	161,527
Working Funds:														-
100.1350.10	500	500	500	500	500	500	500	500	500	500	500	500	500	500
114.1350.10	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
115.1350.10	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
121.1350.10	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800
121.1350.12	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
123.1350.10	2,400	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,092
123.1350.11	3,038	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,003
123.1350.12	-	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,108
996.1350.10	750	-	-	-	-	-	-	-	-	-	-	-	-	58
996.1350.12	1,200	-	-	-	-	-	-	-	-	-	-	-	-	92
Net Corporate Cash Account	**2,753,787**	**(125,428)**	**(1,161,287)**	**1,795,083**	**1,110,466**	**1,569,589**	**1,735,231**	**702,480**	**1,685,186**	**350,679**	**246,004**	**432,629**	**316,845**	**877,790**

2009 CASH	DEC. '08	JAN. '09	FEB. '09	MAR. '09	APR. '09	MAY. '09	JUN. '09	JUL. '09	AUG. '09	SEP. '09	OCT. '09	NOV. '09	DEC. '09	13-month avg
Total Consolidated Cash	352,495	314,097	264,354	331,280	353,420	366,049	87,471	391,946	229,034	233,676	352,029	378,487	275,009	302,257
Less:														
Ppd Dividends 2380	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Funds:														-
100.1350.10	500	500	500	500	500	500	500	500	500	500	500	500	500	500
114.1350.10	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
115.1350.10	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
121.1350.10	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800
121.1350.12	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
123.1350.10	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150	3,150
123.1350.11	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
123.1350.12	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
996.1350.10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
996.1350.12	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Corporate Cash Account	**316,845**	**278,447**	**228,704**	**295,630**	**317,770**	**330,399**	**51,821**	**356,296**	**193,384**	**198,026**	**316,379**	**342,837**	**239,359**	**266,607**

EXHIBIT JVM-2
FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU

Florida Public Utilities Company

BARE STEEL & TUBING REPLACEMENT PROGRAM
Remaining Cost to Complete Program
October 1, 2008

South Florida Division

Mains	Miles	Remaining Footage	Install $/foot	Total $
Unprotected Bare Steel, Cathodically protected Bare Steel and Cast Iron [46,370' installed to date]	194.2	1,025,470	$ 25.00	$ 25,636,750

Mains	Miles	Footage	Install $/foot	Total $
Steel Tubing	3.3	17,500	$ 15.00	$ 262,500

Services	Remaining Units	$/unit	Total $
Bare Steel Services [560 installed to date]	8,797	$ 830.00	$ 7,301,510

Total $ 33,200,760

Central Florida Division

Mains	Miles	Remaining Footage	Install $/foot	Total $
Unprotected Bare Steel [61,691' unstalled to date]	15.7	82,981	$ 20.00	$ 1,659,620

Mains	Miles	Footage	Install $/foot	Total $
Steel Tubing	6.0	31,680	$ 12.00	$ 380,160

Services	Remaining Units	$/unit	Total $
Bare Steel Services [300 installed to date]	2,805	$ 765.00	$ 2,145,825

Total $ 4,185,605

TOTAL CONSOLIDATED DIVISIONS $ 37,386,365

Yearly Amortization Over 60 years $ 623,106

EXHIBIT JVM-3
FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU

Florida Public Utilities Company
GAS RATE CASE
ADJUSTMENTS FOR BARE STEEL REPLACEMENT PROJECT
2009

TOTAL PROPOSAL		DEC .'04	JAN. '05	FEB. '05	MAR. '05	APR. '05	MAY. '05	JUN. '05	JUL. '05	AUG. '05	SEP. '05	OCT. '05	NOV. '05	DEC. '05	13-MONTH AVERAGE	12-MONTH TOTAL
1010.3761 - MAINS		-	(38,804)	(77,608)	(116,412)	(155,216)	(194,020)	(232,824)	(271,628)	(310,432)	(349,236)	(388,039)	(426,842)	(465,645)	(232,824)	
1010.3801 - SERVICES		-	(13,122)	(26,244)	(39,366)	(52,488)	(65,610)	(78,732)	(91,854)	(104,976)	(118,098)	(131,219)	(144,340)	(157,461)	(78,732)	
		-	(51,926)	(103,852)	(155,778)	(207,704)	(259,630)	(311,556)	(363,482)	(415,408)	(467,334)	(519,258)	(571,182)	(623,106)	(311,556)	
4030.1 FOR 3761	0.026		(84)	(168)	(252)	(336)	(420)	(504)	(589)	(673)	(757)	(841)	(925)	(1,009)		(6,558)
4030.1 FOR 3801	0.075		(82)	(164)	(246)	(328)	(410)	(492)	(574)	(656)	(738)	(820)	(902)	(984)		(6,396)
TOTAL 4030.1			(166)	(332)	(498)	(664)	(830)	(996)	(1,163)	(1,329)	(1,495)	(1,661)	(1,827)	(1,993)		(12,954)
1080.3761 - MAINS		-	84	252	504	840	1,260	1,764	2,353	3,026	3,783	4,624	5,549	6,558	2,354	
1080.3801 - SERVICES		-	82	246	492	820	1,230	1,722	2,296	2,952	3,690	4,510	5,412	6,396	2,296	
		-	166	498	996	1,660	2,490	3,486	4,649	5,978	7,473	9,134	10,961	12,954	4,650	
4050.1 - AMORTIZATION OTHER GAS PLANT			51,926	51,926	51,926	51,926	51,926	51,926	51,926	51,926	51,926	51,924	51,924	51,924		623,106

ABOVE AND BEYOND: 566,308 > 623,106 = 9.115% (of the increase is above the new amount)

		DEC .'04	JAN. '05	FEB. '05	MAR. '05	APR. '05	MAY. '05	JUN. '05	JUL. '05	AUG. '05	SEP. '05	OCT. '05	NOV. '05	DEC. '05	13-MONTH AVERAGE	12-MONTH TOTAL
1010.3761 - MAINS		-	(3,537)	(7,074)	(10,611)	(14,148)	(17,686)	(21,223)	(24,760)	(28,297)	(31,834)	(35,371)	(38,908)	(42,442)	(21,222)	
1010.3801 - SERVICES		-	(1,196)	(2,392)	(3,588)	(4,784)	(5,981)	(7,177)	(8,373)	(9,569)	(10,765)	(11,961)	(13,157)	(14,353)	(7,177)	
		-	(4,733)	(9,466)	(14,200)	(18,933)	(23,666)	(28,399)	(33,132)	(37,866)	(42,599)	(47,332)	(52,065)	(56,795)	(28,399)	
4030.1 FOR 3761	0.026	-	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(61)	(69)	(77)	(84)	(92)		(590)
4030.1 FOR 3801	0.075	-	(7)	(15)	(22)	(30)	(37)	(45)	(52)	(60)	(67)	(75)	(82)	(90)		(576)
TOTAL 4030.1		-	(15)	(30)	(45)	(61)	(76)	(91)	(106)	(121)	(136)	(151)	(167)	(182)		(1,166)
1080.3761 - MAINS		-	8	23	46	77	115	161	214	276	345	421	506	598	215	
1080.3801 - SERVICES		-	7	22	45	75	112	157	209	269	336	411	493	583	209	
		-	15	45	91	151	227	318	424	545	681	833	999	1,181	424	
4050.1 - AMORTIZATION OTHER GAS PLANT		-	4,733	4,733	4,733	4,733	4,732	4,732	4,732	4,733	4,733	4,734	4,734	4,734		56,798

EXHIBIT JVM-4
FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU

Florida Public Utilities Company
GAS RATE CASE
ADJUSTMENTS FOR AEP CONTRIBUTIONS
2009

HEADING	DEPR. RATE	DEC. '08	JAN. '09	FEB. '09	MAR. '09	APR. '09	MAY. '09	JUN. '09	JUL. '09	AUG. '09	SEP. '09	OCT. '09	NOV. '09	DEC. '09	13-MONTH AVERAGE	12-MONTH TOTAL
1010.376 - MAINS		2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,202	2,461,203	
4030.1 FOR 3761	0.026		5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333	5,333		63,996
1080.376 - RESERVE MAINS		-	(5,333)	(10,666)	(15,999)	(21,332)	(26,665)	(31,998)	(37,331)	(42,664)	(47,997)	(53,330)	(58,663)	(63,996)	(31,998)	
1860.4- Unamortized AEP		(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	(2,461,202)	

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EXHIBIT JVM-5
FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU

Florida Public Utilities Company

GAS RATE CASE

PROPOSED PERCENTAGE OF REVENUE REQUIREMENT INCREASED TO ALLOW FOR RECOVERY OF COST AND EXPENSES ASSOCIATED WITH THE CONSTRUCTION OF THE SOUTH FLORIDA OPERATIONS CENTER

2009

	DESCRIPTION	REFERENCE		
1	Change In Rate Base:			
	Plant - Structures and Improvements	Below	$ 4,800,000	
	Reserve - Struct & Improvements	Below	$ (60,000)	
	Net Increase in Rate Base			$ 4,740,000
2	REQUESTED RATE OF RETURN	Schedule G-3 (D-1)		8.74%
3	N.O.I. REQUIREMENTS	LINE (1) × LINE (2)		$ 414,276
4	Associated Expenses:			
	Real Estate Taxes	Estimated	$ 114,079	
	Depreciation Expense	Below	$ 120,000	
	Tax Effect	@ .3763	$ (88,084)	
	Total Expenses			$ 145,995
5	N.O.I DEFICIENCY	LINE (2) + LINE (4)		$ 560,271
6	Net Operating Income Multiplier	Schedule G-4		1.62330
7	Total Revenue Requirement	LINE (5) × LINE (6)		$ 909,488
8	Total Base Revenues (Energy Charge Only)	E-1, Page 2 of 5		$ 22,533,676
9	**PROPOSED INCREASE TO BASE RATE - TO INCLUDE OPERATION CENTER**			**4.036%**

HEADING	DEC. '08	JAN. '09	FEB. '09	MAR. '09	APR. '09	MAY. '09	JUN. '09	JUL. '09	AUG. '09	SEP. '09	OCT. '09	NOV. '09	DEC. '09	13-MONTH AVERAGE	12-MONTH TOTAL
1010.390 - STRUCTURES	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	4,800,000	
4030.1 FOR 390: @ 0.025 per year		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000		120,000
1080.390 - RESERVE-STRUCTURES	-	(10,000)	(20,000)	(30,000)	(40,000)	(50,000)	(60,000)	(70,000)	(80,000)	(90,000)	(100,000)	(110,000)	(120,000)	(60,000)	

DIRECT TESTIMONY
OF
APRIL LUNDGREN,
IN

FLORIDA PUBLIC UTITITIES COMPANY
DOCKET NO 080366-GU

IN RE: PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY
FOR A NATURAL GAS RATE INCREASE

Q. Please state your name, affiliation, business address and summarize your academic background and professional experience.

A. My name is April Lundgren. I am the Senior SEC Accountant for Florida Public Utilities Company. I began working for the Company in 2001 as the Financial Accountant, was promoted to Senior Financial Accountant, and subsequently to my current position as Senior SEC Accountant. Between January 2005 and May 2006, I held the position as the Project Controller at Florida Power & Light for several wind plants as well as various gas plants outside the state of Florida. My current responsibilities include SEC reporting, budget forecasting, internal control compliance and documentation, research and application of new accounting guidance, and special projects. Additionally, I coordinate the audits for both external reporting and internal controls. I graduated from Florida Atlantic University in 2003 with a Bachelor of Business Administration, majoring in Accounting.

Q. How did you project O&M expenses for 2008 and 2009?

A. The historic year 2007 O&M expenses provide the basis for most 2008 and 2009 expense items. We first broke each account into its payroll and non-payroll components for the historic base year. We made adjustments to the payroll and non-payroll components to "normalize" the expenses for 2007. The separate components (payroll and non-payroll) of each O&M expense account were projected using the adjusted 2007 expenses multiplied by one of several trend factors. Expense items for which deviation from the trended amount is anticipated have been adjusted for specific cost estimates or other increases and decreases above and beyond the trended amounts. Schedule G-6 pages 6 & 7 contain a listing of the over and above adjustments to the trended amounts. Schedule G-6 page 3 contains a listing of the direct projections and basis used. The most commonly used trend factors for payroll-related expenses include Payroll and Payroll x Customer Growth while the most commonly used trend factors for non-payroll-related expenses include Inflation and Inflation x Customer Growth. We have applied trend factors that are most appropriate for the accounts in question and we have made sure that the applications of these factors have produced reasonable results. Witness Camfield has included in his testimony the basis and computation for the inflation trend factors. The payroll trend factor is based on historical data and the experience of the Company's Human Resources Director and is his best estimate of what we expect the payroll increases to be for both 2008 and 2009. The customer growth and unit growth are based on our projections used within this rate proceeding. The methodology for these projections has been provided by our consultants and explained in the testimony of Witness Schneidermann. A list of the projection factors used is located on Schedules G-2 (C-5) page 7 and G-6 page 3.

Q. Did the Company use any actual data for 2008?

A. Yes, in part. Actual monthly amounts were used for the income statement for January – April 2008. When appropriate, as expenses were projected on an annual basis, the difference between actual and total projected was spread over the remaining months in 2008.

Q. Can you explain the basis for some of the expenses outside of those based on historical data trended to the projected test year?

A. Operation & Maintenance over and above adjustments and Direct projections were made to certain accounts outside of trending historical data. A detailed listing of the over and above adjustments has been included in the filing under G-6 pages 6 & 7. A detailed listing of the direct projections has been included in the filing under G-6 page 3. The following questions will explain each of the Corporate Accounting, Executive and Customer Relations over and above adjustments separately, as well as the direct projections for A&G accounts. For the remaining adjustments and direct projections we have utilized the knowledge and experience of our management team to estimate future costs. Don Kitner, General Manager, has included testimony to explain the Central Florida and South Florida Operations adjustments. Marc Schneidermann, Corporate Service Manager, has included testimony to explain the Corporate Services adjustments. Marc Seagrave, Marketing Director, has included testimony to explain the Corporate & South Florida Marketing adjustments.

DIRECT PROJECTION TESTIMONY

Q. Explain the direct projection of Admin & General Salaries account 920.

A. The Company had numerous positions staffed by temporary personnel and contractors in 2007 and 2008. We have been making efforts to fill these positions with permanent personnel and reduce our reliance on temporary staffing and consultants. We have successfully staffed several positions in our Accounting and

Information Technology Department. As such, applying trend factors to this account will not achieve accurate results for 2008 and 2009 projections. To arrive at an appropriate projection for 2008 and 2009 expense, we analyzed account 920 by payroll charges for each corporate position. Data from the historic year ended 12/31/07 has been normalized and projected at appropriate payroll trend factors of 5.5% for both 2008 and 2009. We have made adjustments to the expense to reflect vacancies, retirements, turnover and replacements.

Q. Is the Company planning to hire the new Compliance Accountant to perform Internal Audit functions for the Corporate office, and is it proper for recovery in the Company's base rate proceeding?

A. Yes, the Company is planning to hire this position and it is proper for recovery in this rate proceeding. The Company has determined that based on the requirements of the Sarbanes Oxley Act of 2002, Section 404, Management Assessment of Internal Controls, we will continue to be faced with increasing internal control requirements. We have also determined that it will be prudent and necessary to hire an internal auditor to assist with the documentation requirements of 404, the internal controls testing, and overall internal controls necessary for the Company. Along with the internal audit requirements, the overall workload continues to increase within the accounting department, and an increase in staff is required at this time to meet the workload of the department.

This position will be responsible to coordinate all of our internal control activities including risk assessment, control documentation, testing, and coordination of efforts of our internal control subcontractor. We have incurred costs associated with internal control efforts; however, the overall workload of the accounting department continues to increase, in addition to the efforts required for internal control functions. Taking both of these factors into consideration, the over and above increase to our 2007 historic year will require this additional position and expenditure beginning in 2009. Internal personnel and temporary staff have been performing some of these functions during 2008.

We were slightly delayed in the process of hiring this position, but we expect to either have a full time candidate hired in this position by January 2009 or temporary personnel to cover the duties until such time a permanent candidate can be hired. We feel it is appropriate to recover the annual amount of the salary plus benefits since the base rate final rate recovery will begin after the time that this position is hired, and the revenues will match the expenses.

Q. Explain the direct projection of Office Utility Expense account 9214.

A. Using trended projections does not accurately project expenses for this account as the cost of electricity and natural gas has increased at rates greater than inflation and accounts for a significant portion of this increase. Also, the decline in overall economic conditions has caused increases to costs of products and services. As observed through historical 2008 data, inflationary increases to this account significantly understates the actual expense incurred. To more accurately project 2008 expenses, we have annualized historical data from January – April 2008. We then trended 2009 projections by increasing our 2008 projections by the inflation trend factor of 1.07. Please refer to Witness Camfield's testimony for the computation of the inflation trend factor.

Q. Explain the direct projection of Miscellaneous Office Expense account 9215.

A. The Company had numerous positions staffed by temporary personnel and contractors throughout 2008 that were charged to this account. We have been making efforts to fill these positions with permanent personnel and reduce temporary staffing and consultants. We have successfully staffed several positions in our Accounting and Information Technology Department. As such, the Company increased 2008 for the use of temporary staff and consultants but we have assumed a return to 2007 historical levels for 2009 and have applied appropriate trend factors to this account from 2007 for 2009 projections to account for cost and inflationary increases. The 2008 adjustment was based on annualizing historical data for January-April 2008.

Q. Explain the direct projection of Outside Services Other account 9231.

A. The Company has experienced increasing requirements in many areas due to new regulations and requirements relating to Sarbanes-Oxley, the IRS, new pension accounting requirements and other complex accounting areas. To comply with these regulations and requirements, the Company utilizes consultants with many years of experience in tax accounting and other specialized areas. The additional adjustment to trend projections reflects the anticipated cost for these consultants by type of service. The basis for this computation utilizes the historical hourly rate multiplied by the anticipated number of hours worked by consultants. Management has estimated what items will be recurring and will require ongoing consulting services over the next several years.

Q. What is the support for outside audit and accounting costs (9233) included in the projected test year?

A. Sarbanes Oxley (SOX) and 404 requirements have caused significant increases to our external and internal audit fees over the last several years. As our market cap approaches $75,000,000 (triggering Accelerated filer status) we must also consider the increase in our audit costs in complying with the additional rules and requirements of SOX. The 2009 projected test year includes additional audit costs related to current Sarbanes Oxley requirements as well as those that will be required as it relates to accelerated filing status. Audit fees will increase significantly due to factors beyond our control to comply with the rules in Sarbanes Oxley Section 404. We will be required to obtain external auditor certifications and the fees associated with that work have been included in our projected test year. Our current external auditors provided us with our estimated cost to perform the additional services that will be required. We appropriately included those costs in our 2009 projections. In addition to internal and external audit fees, our projection includes fees for goodwill impairment testing, pension and 401k audits, and tax consulting work. Many of these items have been projected at the quote provided by the vendor. For the remaining items, we utilized trended historical data to project future costs. All of these costs are recurring.

Q. Explain the direct projection of Property Insurance account 924.

A. Historical transactions for this account in 2007 included recovery of $163,500 of storm costs, which fully amortized our remaining deferred storm damages on the books. In 2008, we increased historical for inflation but reduced this projected expense by the above recovery of $163,500. For 2009, we increased the expense $87,000 to account for the current request for annual storm damage accrual.

The current reserve for property damage is at $788,918 as of September 30, 2008. This balance is the result of over-earnings through Commission order being applied to the Storm Reserve since 2007. This amount will be reduced for any storm charges recorded in October - December 2008. We feel this amount of reserve is not adequate for the following reasons:

1. The replacement value of all mass property items, such as mains, services and meters, which are subject to some level of damage, is $164 million.
2. Using a damage reserve of just ½ of 1% on the replacement value of all mass property items would require a damage reserve of $820,118.
3. The current reserve on the books is only $788,918 leaving a deficiency of $31,200 to be recovered over an eight (8) year period at $3,900 per year.
4. The estimated storm damage expense we expect to incur each year based on the eight (8) year period 2000-2007 is $83,000 per year. Therefore we will need to recover a total of $87,000 annually for the next 8 years. Should storm activity continue at levels experienced in recent years, it may be appropriate to increase the annual storm accrual by an additional $50,000

per year, but we held the expense to a more conservative amount for this projection.

Q. **Why is it prudent to require the customers to provide the funds for a storm accrual?**

A. The Company has maintained a storm reserve to avoid having to collect any sustained damages from our customers after a storm's impact. This would require costly regulatory action after each major storm impact. Having a reserve also allows the Company to absorb damages from year to year without affecting normal operations.

Q. **Explain the direct projection of General Liability account 9252.**

A. The workers' comp and general liability insurance components of this account have been projected at cost estimates provided by the vendors. The self-insurance component of this account has been projected using a 3 year historical average. Due to the unusual amount of claims in 2007, this approach reflects a more appropriate projection methodology as it helps bring the 2007 expenses to a more normalized level and what is expected on an ongoing basis in the future.

Q. **Explain why the allocation factor for accounts 9261, 9262, 9263, 9264, 9265, and 928 use the allocation percentages associated with clearing to regulated segments (1840) as opposed to those associated with clearing to both (1849).**

A. Accounts 9261 – 9265 have a component of the total cost that is capitalized, a component that is allocated to non-regulated operations, and a component that is allocated to regulated operations. The non-regulated and capitalized portion is removed before allocation factors are applied. The remaining portion is then allocated to regulated operations. Account 928 is strictly regulated expenses and are either allocated if appropriate, or directly charged to the appropriate utility type.

Q. What is the support for pension costs (9261) included in the projected test year?

A. We received estimates from our actuary on our pension costs for 2009 and have included these amounts in the projected test year as a direct projection. This expense has been allocated using payroll dollars as a basis and is most appropriate to use since this is a payroll related expenditure. Twenty percent of this cost is allocated to non-regulated operations and capital accounts based on payroll dollars. The remaining balance is then allocated on a payroll basis to regulated operations. Sixty-seven percent of regulated costs are allocated to natural gas. Recent economic conditions of the market and items outside of our control have caused historical pension costs to increase significantly over the last several years and is expected to further increase our pension costs in the next one to five years. In an effort to control these costs the Company recently implemented a 401K plan for all new hires. Current actuarial projections forecast our expense to increase in 2009 from the historical amount. This cost is a payroll related cost necessary to provide customers with adequate service to operate our company effectively and this expenditure is prudent for recovery from our customers.

Q. Explain the direct projection of Employee benefits - other account 9262 & Employee benefits – medical account 9265.

A. Historically, medical expenses were recorded to account 4010.9262 along with other miscellaneous employee benefits. In 2008 we began recording the medical benefit separately to account 4010.9265. When analyzing the projections to historical data, both accounts must be considered. For account 9265, we pulled out the transactions specific to medical from the 9262 account in 2007 and projected 2008 based on an 11.4% increase. For 2009, the percentage was revised to 6.5% to match the estimate provided by the vendor. Medical costs have been increasing nationwide and are for the most part non-controllable by companies. It is a necessary benefit for our employees and the costs are prudent. The trend in increasing costs has necessitated an additional adjustment of $233,320 in 2009. This adjustment represents the average cost over the level expected in 2009 incurred over a four year period (2009 – 2012) at an increase rate of 6% to 15%. The Company has been informed by our insurance carrier that we should expect a 15% annual increase in future years. It is appropriate to request the additional adjustment for recovery of the average medical expense expected during the next four years as this period is historically used to represent the time period between rate cases.

Account 9262 has been projected at historical amounts (less the component identified as medical) increased for inflation. The company-wide expense is allocated to natural gas based on payroll allocation factors.

Q. Explain the direct projection of Retiree benefits – post retirement account 9263.

A. This account was projected based on cost estimates provided by the vendor AON. The costs were reduced by 20% to reflect historical capitalization rates and allocated amounts to non-regulated operations based on actual payroll. The remaining 80% was allocated according to our 1840 allocation percentages with a payroll basis. This resulted in 67% of the remaining expense being recorded to natural gas.

Q. Explain the direct projection of regulatory commission account 928.

A. This account has been adjusted from the trend by $122,390. This amount represents the new rate case amortization of $211,020 less the prior amortization of $88,630. Witness Martin has included in her testimony additional support for this adjustment.

Q. Summarize your position on Uncollectibe Accounts Expense (904) for the calendar year 2008 and the Projection Year 2009.

A. The Uncollectible Accounts Expense is derived from historical write-off rates and current billing and collection procedures.

The Uncollectible Accounts expense for 2008 in the amount of $269,988 was based on a three-year average historical write-off rate of .0043, times the "adjusted revenues" of $62,790,000 for 2008. The Florida Public Service Commission (the Commission) argued in the last gas rate case "in prior cases we have tested the reasonableness of a company's bad debt expense by using a three or a four-year average of net write-offs as a percent of revenues. A three-year average was used in the Company's last rate case."(FPSC Order No. PSC-04-1110-PAA-GU, p.22; Issued November 8, 2004).

The Uncollectible Accounts expense for 2009 was based on the 2008 expense increased for the projected 2009 write-offs due to a large increase in PGA driven typical bills. These PGA increases coupled with the regulatory lag in not being able to increase customer deposits until at least twelve months of higher bills have been rendered (FPSC rule 25-7.083(3) and FPUC tariff Sheet 13-1) will cause the write-off of bad debts to increase approximately 111% over historical amounts. This coupled with an expected 10% increase in write-offs due to the economic downturn resulting in additional foreclosures and failed businesses have resulted in a $369,187 increase in projected Uncollectible Accounts Expense in 2009. The expected 10% increase in write-offs due to the economic downturn appears to be very conservative based on recent events as net write-offs in 2008 are presently increasing at a 30% rate over the past two years. It is probably appropriate to increase this expense projection further from our initial projection.

Q. **Describe the methodology for projecting piping and conversion expenses 9161.**

A. The direct expense projection for piping and conversion costs are $432,000 and $413,000 for 2008 and 2009 respectively. The projected expense is based on the monthly new expenses (actual to April 2008; projected May 2008 – Dec 2009) amortized over 7 years for piping and 5 years for conversions. The projected new monthly expenses for 2009 are based on the average of the monthly expenses for the prior three years. Atlantic Utilities, which represents amortized annual expense of $49,000 will be fully amortized in December 2008 and is therefore not included in the 2009 projections. Our projections also include an increase in new conversion costs related to the demand for tankless water heaters of $70,000 (spread evenly over the year and amortized for 5 years).

Q. Explain the direct projection for account 4080.1 Ad valorem.

A. A comparison of the 2008 tax bill and projections based on historical data increased for inflationary trends shows our actual costs incurred are increasing at higher rates. The Company utilized the 2008 tax bills as a basis for our 2008 projections and increased the 2008 expense by the inflationary trend of 2.74% to project 2009 expenses.

OVER & ABOVE ADJUSTMENTS TESTIMONY

Q. Is the $20,000 included for the travel and training related to the addition of a Compliance Accountant and increase in the number of internal audits appropriate?

A. Yes. The Company audits the inventory and cash of each division on an annual basis. However, we also need to perform additional audits based on related Section 404 controls in Sarbanes Oxley, and other operational audits depending on the risk assessment and the need to improve efficiencies or to test controls. The estimated cost for each year would be between $1,000 and $2,000 per year per audit depending on location. We estimate that we would need an additional four to six audits per year beyond our current levels. Although our locations are all within the state of Florida, all trips to divisions require overnight stays at hotels and either car or air travel, depending on location and time constraints. Meals and other travel related expenses are also included. A breakdown is as follows (two people conducting a material and supplies inventory in Marianna):

Hotel ($85 per room, X 2 rooms X 4 nights) =	$ 680
Meals ($36 per person, X 2 people, X 5 days) =	$ 360
Transportation (481.63 miles X $0.585 per mile) =	$ 565
Misc. Travel related costs (per company policy) =	$ 90
Total =	$1,695
Increase for 5 trips ($1,695 x 5) =	$8,475

In addition to inventory and audit related trips to the Company's divisions, the Compliance Accountant will be required to attend on average one training seminar every two months (or 6 per year) to stay current with new guidance, requirements, and regulations as set forth by governing authorities. The estimated cost for a local seminar is $2,000 per course, based on historical expense. For six courses the estimated cost would be $12,000. The total cost for trips to divisions ($8,475) and training courses ($12,000) would be $20,475, or approximately $20,000. Fifty-one percent of this expense is allocated to natural gas based on payroll, or $10,200.

Q. Why is the Company seeking recovery of costs relating to a tax consultant?

A. The Company has experienced increased demands relating to tax work. Multiple ongoing IRS audits, increased complications within the Company's tax return, new FIN 48 requirements and ongoing special tax projects have caused a need for a tax consultant. The Company will continue to face these complexities and requirements in future years and will therefore require the resources to meet these demands. These costs will be recurring.

Q. Is $78,000 an appropriate projection for this service?

A. The Company has included $78,000 in our projections to recover the cost of a tax consultant. This cost is based on our current cost of $75 per hour for one-half of a year (1040 hours). Because this cost was not incurred in 2007, the Company has added the entire amount as an adjustment to project 2009. These costs have been reviewed for reasonableness and are expected to be incurred annually. 51% (or $39,780) of this expense is allocated to natural gas based on adjusted gross profit.

Q. Please explain the property tax adjustment of $114,079 in 2009.

A. The Company will be constructing a building for the South Florida Operations Facility in 2009 - 2010. We had originally projected a related increase to the property taxes in 2009. We now anticipate completion of the facility in 2010, however, we feel it is appropriate to seek recovery of the increase as it is an uncontrollable increase the Company will incur over most of the period that the new rates will be in effect. The anticipated increase in property tax relating to the building is expected to be $114,079, computed using the actual rate on a similar item in Palm Beach County, however as an alternative, the Commission may feel it is more appropriate to combine this tax expense with the special recovery of the new office building as an alternative.

Q. Why has the Company added an over and above adjustment of $8,855 for Infinium software maintenance?

A. Historically, the Infinium software maintenance fees have increased at a rate of 8% which is higher than the normal inflation rate. We have included known actual changes in our projections and used the actual historical increase and projected this same increase for 2009. Fifty-four percent (or $4,782) of this expense is allocated to natural gas based on allocated common plant.

Q. Explain the $14,751 adjustment for SSA Global report writer and budget maintenance.

A. The Company has historically utilized Excel templates to prepare the budget. Due to the complex calculations, linked files, and integrated components of our budget, we are quickly exceeding the capabilities of this application. We have researched various applications designed to meet our budget and forecasting needs and have included in our 2009 projections a budget and report writer application from SSA Global. We have revised the application quote received from the vendor in our projection to account for inflation.

The Company has included $7,966 (or 54% of $14,751) in 2009 for recovery of maintenance on this software application. The allocation percentage of 54% to natural gas is based on allocated common plant. Although we will not incur the maintenance fees until years 2010 and beyond, we will incur approximately the same cost in 2009 as training expense. Because we will be incurring maintenance fees on an annual basis going forward, it is appropriate to seek recovery of these costs.

Q. Why is an adjustment for Annual Report and Stock Exchange fees appropriate?

A. The cost for producing the 2007 annual report was significantly less than a typical annual report due to the paper weight and the type of cover. The adjustment for the stock exchange fees is the difference between historical cost and the future cost estimate provided by the vendor. The portion of the cost increase for 2009 that has been allocated to natural gas is $4,408.

Q. Explain the over and above adjustments relating to personnel not charged to 920 A&G.

A. For the adjustments relating to personnel, we have made adjustments to reflect our expectations for each year's staffing levels. For any occurrence where a position was staffed in the historic year ended 12/31/2007 but vacant for part of the projected year ended 12/31/2008, or we anticipate the position will be vacant any portion of the projected test year ended 12/31/2009, we have decreased our projected expenses. For any occurrence where a position was vacant for part of the historic year ended 12/31/2007 but we anticipate it will be fully staffed in 2008 or 2009, we have increased our projected expenses. The increase and decrease has been calculated by position based on the annual salary specific to that position and the amount of time the adjustment represents. For example, there is an adjustment relating to the I&M gas utility worker for 2008 and 2009 of $6,200 and $18,600. The position was vacant for 6 months in 2007. The adjustments were calculated as follows:

Annual salary $37,200

Amount of expense included in historic year ended 2007 = 18,600

Position was staffed 8 months in 2008, expense for 2008 = 24,800

Adjustment to 2008 projection = 6,200

Position to be staffed 12 months in 2009, expense for 2009 = 37,200

Adjustment to 2009 projection = 18,600

There are positions for which the 2008 or 2009 annual salary range has also been adjusted for the Company's merit increase percentage projections. This is based on the general manager's estimate of which positions will be receiving merit increases and is not applied in a blanket manner to all personnel adjustments. Witness Kitner has included in his testimony the reasons staffing vacant positions is required for Central and South Florida operations. Witness Seagrave has included in his testimony the reasons for the Marketing positions. The appropriateness of the Customer Relations staffing adjustments is included in this testimony under separate discussion.

Q. Explain the over and above non- personnel adjustments for Central Florida Operations.

A. The non-personnel adjustments for Central Florida operations include an adjustment for the sub-aqueous crossing inspection, intra-coastal crossing location, a GPS dispatching and navigational system, the SummerGlen conversion, training and line locating. Witness Kitner has included in his testimony the nature of each of these adjustments. The adjustment amount for each of these items has been computed as follows:

Sub-aqueous crossing inspection $0 in 2008, $600 in 2009 – This amount is 1/5 of the total cost, based on a vendor quote for $2,860.

Intra-coastal crossing location $4,800 in 2008, $0 in 2009 – Actual cost for line location, 2 days at $2,400 per day.

GPS dispatching and navigational system $6,800 in 2008, $17,700 in 2009 – We purchased 16 connected navigation units with messaging. The annual service cost of each is $599.40. The total cost of $9,590.40 was split between natural gas and propane based on vehicle count, with $8,439.60 representing the natural gas portion. We purchased 33 navigation and location units without messaging. The annual service cost of each is $419.40. The total cost of $13,840.20 was split between natural gas and propane based on vehicle count, with $9,226.80 representing the natural gas portion. The service cost for the connected navigation units ($8,439.60) and the location only units ($9,226.80) provides a total annual service cost to natural gas of $17,666.40, (or $17,700). The 2009 adjustment represents a full year; the 2008 adjustment represents costs incurred for a partial year.

SummerGlen Conversion $57,300 in 2008 and $57,300 in 2009 – Since the SummerGlen conversion occurred in late 2007, we had to normalize the historic year expenses so that our projected test year reflected appropriate expenses as they relate to SummerGlen. $33,300 is for supervision, marketing and office payroll, $12,000 is for field employees and meter reading costs, and $12,000 is for various office expenses.

Operational, technical, safety and leadership training $27,140 in 2009- This adjustment includes training costs for Avanti training, SGA training, Gas training, and FNGA training.

Web based operator qualification training $13,400 in 2008 and 2009 - $100 per license x 134 employees.

Line locating ($12,600) in 2008 – This adjustment represents the decrease in line locating expenses we are experiencing in 2008 based on Witness Kitner's experience as the General Manager of Central Florida Operations.

Q. Explain the over and above non- personnel adjustments for Corporate Services.

A. The non-personnel adjustments for South Florida operations include an adjustment for Smith System training, third party claims administration, license monitoring, Worksteps program, Bulli Ray, SGA Super Week, FGT Shippers meetings, Gas Mart, Occupational health and Safety seminars, Corporate office landscaping, Corporate office painting, Corporate office flooring, and gas distribution integrity. Witness Schneidermann has included in his testimony the nature of each of these adjustments. The adjustment amount for each of these items has been computed as follows:

Smith System $60,950 in 2009 – These costs are based on a vendor quote of $373 per student for 150 students for the DriverDirect standard one day course. Additionally, we have included costs for the five day DriverTrainer course for instructors based on the vendor quote of $1,935 (plus $550 in additional expenses) per student for two employees. Of the total $60,950, $31,085 has been allocated to natural gas based on adjusted gross profit allocation factors.

Third Party Claims Administrator $25,000 in 2009 – These costs are based on the lowest vendor quote. Of the total $25,000, $12,750 has been allocated to natural gas based on adjusted gross profit allocation factors.

Drivers license monitoring $5,000 in 2009 - Based on vendor quote of approximately $3,500 in minimum annual costs for MVRs and monitoring plus approximately $1,500 in monthly monitoring fees based 155 drivers at $9.60 per year each. $2,550 of the total cost has been allocated to natural gas based on adjusted gross profit allocation factors.

Worksteps $60,000 in 2009 – Cost based on vendor quote; the Comprehensive Post Offer Functional Employment Test (at a cost of $150 per employee) and the Fit For Duty RTW Test (at a cost of $150 per employee) for 200 employees (anticipated sample selection). Of the $60,000 total costs, $30,600 has been allocated to natural gas based on adjusted gross profit allocation factors.

Bulli Ray recertification and training $6,000 in 2009 – Costs are based on vendor quote for $1,850 per person for 3 employees. We have included additional costs for travel and hotel. Of the total $6,000 cost, $3,060 has been allocated to natural gas based on adjusted gross profit allocation factors.

SGA Super Week & Safety Committee $3,000 in 2009 – Cost includes 3 day course at $445 per person, hotel and meals of $507 ($169 per day for 3 days) per person, for three employees. We have included additional costs of $144 for mileage, tolls and other miscellaneous costs.

FGT Shippers Meetings ($600) in 2008 and $1,500 in 2009 – Costs based on attending the Summer Operations Meeting and the Shipper's Meeting for 2 employees attending twice per year.

Gas Mart Third party natural gas supply meetings ($2,000) in 2008 and $4,000 in 2009 – The adjustment is based on historical cost of $1,145 for the training course and $910 in travel costs for two people.

Occupational Health and Safety seminars ($300) in 2008 and $3,000 in 2009 – Of the total $3,000 cost for 2009, $1,530 has been allocated to natural gas based on adjusted gross profit allocation factors.

Corporate office landscaping ($3,600) in 2008 and $3,600 in 2009 – Based on vendor quote, $1,750 for 7 of the 45 gallon pots (unit cost of $250), $900 for 20 of the 3 gallon pots (unit cost of $45), $400 for 2 planters with drip system at the office entry, $200 for tax and $400 for delivery and installation. Of the total $3,600 cost for 2009, $1,944 has been allocated to natural gas based on common plant allocation factors.

Corporate office painting $11,750 in 2009 – The adjustment is based on vendor quote of $29,500 for interior painting and $17,500 for exterior painting. The total $47,000 has been allocated over a four year recovery period for an annual cost of $11,750. Of the total annual cost, $6,345 has been allocated to natural gas based on common plant allocation factors.

Corporate office flooring $25,000 in 2009 – The anticipated cost for flooring is $100,000 based on vendor quote. The total has been allocated over a four year recovery period. Of the $25,000 annual cost, $13,500 has been allocated to natural gas based on common plant allocation factors.

Gas distribution integrity $50,000 in 2009 – This cost estimate is based on the knowledge and experience of Management. Witness Schneidermann has discussed the computation of the $50,000 adjustment in his testimony.

Q. Explain the over and above non- personnel adjustments for South Florida Operations.

A. The non-personnel adjustments for South Florida operations include an adjustment for GPS, Dispatching and Navigational System, Bridge crossing repairs and maintenance, Training, Line locating and an M&J allocation correction. Witnesses Kitner and Martin have included in their testimony the nature of different components of these adjustments. The adjustment amount for each of these items has been computed as follows:

GPS, Dispatching and Navigational System $21,600 in 2008 and $43,200 in 2009 - We purchased 25 connected navigation units with messaging. The annual service cost of each is $599.40, (or $600 rounded). The total service cost of $15,000 was split between natural gas and propane based on vehicle count, with $14,000 representing the natural gas portion. We purchased 80 navigation and location units without messaging. The annual service cost of each is $419.40, (or 400 rounded). The total service cost of $32,000 was split between natural gas and propane based on vehicle count, with $30,000 representing the natural gas portion. The service cost for the connected navigation units with messaging ($14,000) and the navigation and location units without messaging ($30,000) provides a total annual service cost to natural gas of $44,000. An adjustment of $43,200 has been included for 2009 and represents a full year; the 2008 adjustment represents costs incurred for a partial year.

Bridge crossing repairs and maintenance $26,250 in 2009 – The adjustment is based on the vendor quote increased by approximately 6.5% for a total of $105,000. This cost has been allocated over a four year recovery period for an annual cost of $26,250.

Operational, technical, safety and leadership training $65,000 in 2009 – This adjustment includes Avanti training, SGA training, Gas training services, FGNA training, and gas technology institute training. The adjustment has been calculated by course at unit cost.

<u>Line locating</u> ($140,000) in 2008 and ($75,000) in 2009 – The adjustment was calculated based on the historical activity for 2007 as compared to 2008. The decrease was carried into 2009 at reduced levels as expected until activities are expected to return to a normal level.

<u>M&J allocation correction</u> $100,000 in 2008 and $100,000 in 2009 – Witness Martin has included this adjustment in her testimony.

Q. Explain the over and above non- personnel adjustments for Corporate and South Florida Marketing.

A. The non-personnel adjustments for Corporate and South Florida Marketing include an adjustment for Research & Development, non-conservation industry training, and an SGA initiative. Witness Seagrave has included in his testimony the nature of these adjustments. The adjustment amount for each of these items has been computed as follows:

<u>Research & Development</u> $50,000 in 2009 – This projected cost includes amounts for contributions to organizations such as GTI, AGA and the Florida solar Energy Center to support research and development of such gas utilization equipment as natural gas fuel cells, desiccant dehumidification systems, residential natural gas fueling units and solar water heating with natural gas back up tankless water heaters. It also includes funds for R&D relating to the establishment of a commercial natural gas fueling station, funds for the installation of a desiccant dehumidification unit in a public school, and funds for equipment to

monitor the humidity and performance of the desiccant dehumidification units in our corporate office. The resulting data will serve as a marketing tool to educate our customers.

Non-conservation industry training ($22,500) in 2008 and $10,000 in 2009 – The 2009 adjustment includes $4,000 for 2 employees to attend the Fuel Maker CNG Unit Training course and $6,000 for 2 employees to attend the Carbon Cap & trade certification training course.

SGA initiative $7,820 in 2008 and 2009 – This is based on the Council for Responsible Energy member cost of $0.15 per meter times 52,133 meters in service.

Q. Explain the over and above non- personnel adjustments for Corporate - General.

A. The non-personnel adjustments included in Corporate - General are based on historical costs and are as follows for 2009:

1. $1,102 for Conferences (of which 52% or $573 has been allocated to natural gas based on the allocation factors for utility plant)
2. $2,490 for FNGA annual dues
3. $400 for AGDF annual dues
4. $266 for SGA annual dues

Q. Explain the over and above non- personnel adjustments for Customer Relations.

A. The non-personnel adjustments for Customer relations include an adjustment for Kubra E-bill, Postage, and Envelopes. All of these adjustments are shown below in total while only 53% is allocated to natural gas (based on the customer allocation percentage) and has been included for recovery. The company-wide adjustment amount for each of these items has been computed as follows:

Kubra E-bill $1,200 in 2009 – The origination fee is based on unit cost of $0.05 for 2,000 bills for a total of $100 per month or $1,200 per year.

Postage $11,970 in 2009 – Based on an increase of $0.015 for 114,000 units each month effective June 1, 2009.

Envelopes $448 in 2009 – Based on an increase of $0.004 for 112,000 pieces.

Q. Is the Company's requested increase for the addition of a new CIS Project Analyst position for the Customer Relation department appropriate?

A. Yes. To ensure we are 404 compliant within our local offices, we decided to centralize some of the customer relations duties in order to operate more efficiently. This will also allow the personnel in the local offices to concentrate on their other duties and serve our customers better. This position is necessary to improve customer service and to comply with 404 requirements, and therefore should be allowed for recovery. This position is currently staffed by temporary personnel, and the permanent employee is estimated to be hired in early 2009. The adjustment is calculated at $22 per hour x 2080 hours = $45,760 base salary. This is increased for merit and annual salary increases, over-time typical of this position, and overheads. The adjusted annual expense is $67,520, of which $35,786 is allocated to natural gas.

Q. **Explain the Commission adjustments made to expenses for the historic and projected test years?**

A. The fuel and conservation expenses and revenues have been eliminated from both the historic year and projected years. These items are handled in separate dockets outside of a base rate proceeding and are appropriate for review and approval within those separate proceedings. Revenues and expenses relating to the Company's Area Expansion Program (AEP) have also been eliminated on the same basis. Over-earnings have been adjusted to exclude amounts relating to the over-earnings entries. These are out of period adjustments. We have also eliminated the impacts of prior period tax adjustments from net operating income. The effective tax rate has been included as income tax expense in years presented. Non-regulated depreciation expense has been removed for the plant in service shared by our non-regulated operations. See schedule C-2 & G-2 (C-2) for a summary of these adjustments.

Q. **Does this conclude your written prepared testimony?**

A. Yes.

DIRECT TESTIMONY

DOREEN COX

Of

FLORIDA PUBLIC UTILITIES COMPANY

DOCKET NO. 080366-GU

RE: PETITION FOR NATURAL GAS RATE INCREASE

Q. **Please state your name, title, and business address.**

A. My name is Doreen Cox. I am a Financial Analyst with Florida Public Utilities Company (FPU). My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Q. **What is the scope of your testimony?**

A. In addition to testimony filed jointly with Robert Camfield on cost of capital, I will in this testimony address a variety of other issues related to FPU's rate increase application that are not directly related to cost of capital. First I will outline the methodology applied and assumptions used in our cash forecast. Then I will outline the determination of the projected revenues as it relates to our base rates, fuel and conservation. The over and under recoveries of fuel and conservation will also be covered. Finally I will present the approach taken in this filing regarding our acquisition adjustment from our asset purchase of South Florida Natural Gas (SFNG) in 2003.

Q. Please review your professional background and experience that qualifies you to provide such recommendations.

A. I received a Bachelor of Science Degree in Management from the University of West Indies in 1979, with a concentration in Accounting. In 1990 I earned a Master of Science Degree in Accounting, also from the University of West Indies. I joined FPU in 1999, and I hold the position of Financial Analyst, which reports to the Chief Financial Officer. In this position, I support the CFO, the Accounting and Finance Division of Florida Public Utilities. My position covers a variety of operating and planning responsibilities including project assessment, budget and financial projections, and cash flow analysis. I assist in the preparation of quarterly reports to our Board of Directors, and the compliance monitoring with respect to the Financial Covenants of FPU's long and short-term sources of external funds. I was a witness in the Natural Gas and Electric rate relief proceedings before the FPSC: Docket Numbers 040216-GU and 070304-EI filed in May 2004 and August 2007 respectively.

<u>Cash Forecast</u>

Q. Please describe the methodology used for projecting cash flow requirements for the test year.

A. The cash flow projections are based on expected future cash inflows from normal operating activities and any other known non-operating items. The cash provided by operating activities, along with any other sources of funds, such as financing activities are used to meet our normal operating expenses, construction expenditures, dividend, and sinking fund payments. Additional sources of funding, either debt or equity, is projected when necessary. FPU tries to maintain a balanced capital structure, which in addition to market conditions determines the type of financing the company pursues.

Q. What are some of the main items included in the projections?

A. In addition to capital for system expansion we have projected our major expenses such as pension contributions, medical insurance costs, sinking fund payments on long term debt and dividend payments. We have also projected costs associated with environmental clean-up of manufactured gas plant (MGP) sites in our South and Central Divisions as estimated by our environmental attorney. In May 2008 our attorney estimated that we would have environmental related consulting and legal expenditures of approximately $720,000. Although the probable total liability for clean-up of former MGP sites is between $5.63 million and $18.8 million it is expected that the majority of it will be spent after 2009. Based on the projected cash needs for capital and operational expenses we anticipate that additional sources of funding will be required by mid-2009 and therefore have, projected for issuance of additional capital stock in mid 2009. The gross proceeds of the stock issue are projected to be $15,000,000. FPU, in reviewing alternate sources of financing, strives for an optimal mix of debt and equity, which in the long term would ideally approximate close to a 50:50 ratio. In the past we have been able to successfully delay offering equity, which has a negative impact to our earnings per share, by the sale of our water division in 2003 and more recently by increasing our line of credit with Bank of America. The increase in the short term line of credit in 2008 to $26 million allowed us to delay our efforts to raise capital in 2008. We do, however anticipate having to do an equity offering mid 2009, based on the current projected system expansion, pension contribution and environmental demands. EXHIBIT DC-1

Revenues and Fuel

Q. How were the revenue projections determined for the 2009 test year?

A. Projection factors were developed based on a weather-normalized trend analysis performed by CA Energy Consulting, LLC which is a wholly owned subsidiary of Lauritis R. Christensen Associates, Inc. (Christensen Associates) FPU's rate consultant. The consultants performed a detailed analysis of the historical customer and sales data for December 2004 through July 2008 for each rate class. Statistical analyses were used to determine the relationship between the use per customer (UPC) and weather; as well as the historical change of the UPC over time. Details of the methodology used are provided in Marc Schneidermann's testimony.

Q. Do the revenues you have computed from the sale of natural gas include any revenues for purchase gas adjustment (PGA) and conservation expense?

A. Although fuel and conservation expense recovery projections are included in the filing they are handled in a separate docket and are not included with base revenues in accordance with the Florida Public Service Commission's (FPSC) minimum filing requirements. We have removed these items as an adjustment to both revenues and expenses.

Q. What is the amount of fuel revenues projected for the 2009 test year?

A. Fuel costs for the test year 2009 are projected to be $1.58 per therm. Please reference Docket No. 080003-GU for details on the methodology used to forecast the fuel cost recovery factor. The projected fuel revenues for 2009 are $71.3 million.

Q. How are the test year 2009 operating revenues used in this filing?

A. The projected operating base revenues are used to determine the base revenue requirement for 2009. The projected revenues, by service class, are also a key input in the cost of service study used to determine the proposed interclass revenue allocation.

Q. Do the projected billing determinants accurately reflect the realistic revenues and costs?

A. Yes. The projected billing determinants are reflective of the anticipated usage levels for 2009. Please refer to testimony of Marc Schneidermann for additional details.

Over / Under Recovery

Q. What is the basis used in projecting over or under recovery of fuel?

A. The methodology of fuel projections in Docket 080003-GU provides for projected fuel revenue equal to our fuel expenses with no over or under recovery. Both fuel revenue and expenses have been removed as an adjustment in this filing.

Q. What is the basis used in projecting over or under recovery of conservation?

A. The methodology of conservation projections in Docket 080004-GU provides for projected conservation revenue equal to our conservation expenses with no over or under recovery. They also have been removed as an adjustment in this filing.

Acquisition Adjustment

Q. Please provide a brief history of the acquisition adjustment related to the SFNG asset acquisition?

A. FPU acquired the assets of SFNG on December 14, 2001 for a purchase price of $9.9 million. Included in the purchase price were $1.9 million of intangible assets for customer distribution rights and $1.5 million of tangible goodwill related to the natural gas segment of the business. In our 2004 rate proceeding approval was granted by the FPSC to include $960,376 of the acquisition adjustment in rate base. They found that as a result of the acquisition the former customers of SFNG benefitted through expense reductions, reduced fuel prices, and a higher level of customer service. FPU was therefore allowed to include that portion of the acquisition adjustment in rate base and amortize it over 30 years. These benefits far exceeded the impact of including this $960,376 in rate base.

Q. Do the cost savings and other synergies resulting from the acquisition still exist?

A. Yes. The former SFNG customers continue to benefit in several ways due to the acquisition. FPU continues to provide lower fuel and other cost savings, superior customer service and a lower overall cost of capital to the former SNFG customers. We continue to increase our efficiencies and in 2005 closed the New Smyrna Beach Office resulting in an additional savings of approximately $30,000 in lease payments.

Q. Does FPU deem it appropriate for the remaining balance of the acquisition adjustment to be included in rate base?

A. Yes, the synergies, both tangible and intangible (customer distribution rights) can be more than justified for inclusion in rate base based on the many benefits to our customers resulting from the acquisition as outlined above.

Q. However, has any portion of the remaining FPSC unauthorized acquisition adjustment been included in rate base or net operating income for this rate proceeding?

A. No, although FPU feels that the balance of the acquisition adjustment is more than fully justifiable for inclusion in rate base we have not made any adjustment to rate base or net operating income to include it in this rate proceeding at this time.

Q. Does this conclude your testimony?

A. Yes.

Exhibit DC-1 Page 1 of 3
Docket No. 080366-GU
Witness: COX

Unaudited

FLORIDA PUBLIC UTILITIES
CASH PROJECTIONS
2008 - 2012
IN THOUSANDS

	2008	2009	2010	2011	2012
Operating Revenues	126,113	132,979	137,116	142,573	148,247
Fuel Revenue & Pass-thrus	(74,297)	(77,254)	(80,329)	(83,947)	(86,634)
Gross Profit	51,816	55,725	56,787	58,626	61.613
Other Income - Net (excl taxes & int cap)	730	753	761	798	836
Total	52,546	56,478	57,548	59,424	62,449
DEDUCTIONS:					
Operation & Maintenance (Excl Fuel & Pass thrus)	30,468	31,045	32,365	33,590	34,928
Non-Cash O&M (Storm Resv)	(100)	(100)	(100)	(100)	(100)
Income Taxes Paid	1,796	2,788	2,842	2,443	2,859
Taxes Paid - Other	3,233	3,308	3,421	3,659	3.749
Interest On Long - Term Debt	3,879	3,740	3,603	4,292	4,196
Interest on LOC net of Interest Income	449	777	654	1,008	1,134
Other Interest Payments	446	459	459	477	496
Environmental Clean Up Costs	335	725	274	3,185	225
Dividends Paid	2,824	3,094	3,682	3,846	3,986
Proceeds from DRIP & ESPP	(488)	(507)	(528)	(546)	(565)
Pension Contributions	400	1,791	4,219	3,175	3,003
TOTAL DEDUCTIONS	43,240	47,118	50,891	55,029	53,910
BALANCE	9,306	9,360	6,658	4,395	8.539
Increase (Decrease) in Cash Due to Fluctuation in Certain Assets / Liab / Rev / Exp	(1,516)	0	0	0	0
Less Construction Requirements	17,623	14,228	17,350	14,932	13.557
Net Const. Cash Refunds/(Contributions)	386	401	417	432	447
BALANCE	(10,218)	(5,268)	(11,109)	(10,969)	(5,466)
Proceeds from Water Sale & LWG	300	300	5,813	0	0
(Tax) / Refund on Sale of Water & LWG	0	0	0	0	0
Add Proceeds from Financing - BOA LOC	8,202	(7,800)	6,800	(1,800)	7,000
Less LT Debt Principal Repayments	(1,409)	(1,409)	(1.409)	(1,409)	(1.409)
Less Loan Expenses (LT Debt)	0	0	0	0	0
Add Proceeds from Bond Issue	0	0	0	15,000	0
Less Loan Expenses (Bonds)	0	0	0	(900)	0
Add Proceeds from Equity Issue	0	15,000	0	0	0
Less Expenses (Equity)	0	(900)	0	0	0
Less ST Investments	0	0	0	0	0
Cash Balance - Beginning of Period	3,478	352	275	369	291
Cash Balance - End of Period	352	275	369	291	416
BOA Line of Credit	26,000	26,000	26,000	26,000	26.000
Interest on LOC	17	26	26	26	26
Notes Payable Balance	19,324	11,524	18,324	16,524	23,524
Interest on Borrowings	437	724	595	958	1,101
Unused Portion of LOC	6,676	14,476	7,676	9,476	2,476
Interest on Unused Portion of LOC	10	31	38	24	6
Interest Income	29	5	5	5	5

FLORIDA PUBLIC UTILITIES COMPANY
CASH PROJECTION
BUDGET 2008

TOTAL CONSOLIDATED

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Operating Revenues		13,746,561	11,705,272	11,095,447	9,956,322	9,195,071	9,368,554	9,318,485	9,477,959	8,944,815	9,332,294	10,643,069	13,325,244	126,113,091
Fuel Revenue & Pass-thrus		(7,952,211)	(6,730,066)	(6,549,612)	(5,809,736)	(5,208,195)	(5,447,478)	(5,468,786)	(5,579,188)	(5,059,428)	(5,549,509)	(6,550,245)	(8,392,639)	(74,297,091)
Gross Profit		5,794,350	4,975,206	4,545,835	4,146,586	3,986,875	3,921,076	3,849,700	3,898,771	3,885,388	3,782,785	4,092,824	4,932,605	51,816,000
Other Income - Net (excl taxes & int cap)		52,995	93,679	69,362	88,991	24,570	78,073	42,605	78,359	53,133	25,425	66,853	55,957	730,000
Total		5,849,345	5,068,884	4,615,197	4,237,577	4,011,445	3,999,148	3,892,304	3,977,130	3,938,520	3,808,209	4,159,677	4,988,562	52,546,000
DEDUCTIONS:														
Operation & Mtnce Excl Fuel etc		3,408,235	2,925,405	2,672,936	2,439,355	2,344,270	2,305,580	2,263,811	2,292,465	2,284,596	2,224,265	2,406,567	2,900,356	30,467,642
Non-Cash O&M (Storm Resv)		(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(100,000)
Income Taxes Paid					448,955		448,955			448,955		0	448,955	1,795,820
Taxes Paid - Other		243,846	13,307	150,813	94,142	62,735	81,210	247,241	91,353	50,307	201,782	1,985,000	11,264	3,233,000
Interest On Long - Term Debt						754,325	363,200					685,754	363,200	2,166,479
Interest on Additional LT Debt	6.85%	256,800			256,800			256,700			256,500			1,026,800
Interest on Environmental Expenditure		0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Private Activity Bond	4.90%					343,000						342,400		685,400
Interest on LOC		34,100	27,300	24,849	29,567	30,893	36,385	37,977	34,349	37,117	40,648	52,715	62,960	449,061
Other Interest Payments		0	0	0	222,800	222,800	0	0	0	0	0	0	0	445,600
Payment Of Environmental Clean Up		310	4,795	25,005	603	100,495	19,447	5,945	4,183	43,429	43,429	43,429	43,429	334,500
Dividends Paid - Preferred		7,125	0	0	7,125	0	0	7,125	0	0	7,125	0	0	28,500
Dividends Paid - Common		681,000	0	0	683,000	0	0	714,000	0	0	717,000	0	0	2,795,000
Proceeds Form Sale - Common Stock		(158,499)	0	0	(84,111)	0	0	(164,455)	0	0	(80,892)	0	0	(487,957)
Pension Contributions										400,000				400,000
TOTAL DEDUCTIONS		4,464,584	2,962,473	2,865,270	4,089,902	3,850,185	3,246,442	3,359,811	2,414,018	3,256,071	3,401,725	5,507,533	3,821,832	43,239,845
BALANCE		1,384,761	2,106,412	1,749,927	147,675	161,260	752,706	532,493	1,563,113	682,449	406,484	(1,347,856)	1,166,731	9,306,155
Increase (Decrease) in Cash Due to Fluctuation in Certain Assets & Liab.		(2,298,117)	283,644	(16,914)	957,029	78,907	(705,490)	573,709	(388,468)	-	-	-	-	(1,515,700)
Construction Requirements (including AEP)		647,009	700,579	1,382,970	869,443	890,086	772,723	605,121	613,601	2,059,417	2,525,257	2,765,017	2,592,517	16,423,740
Construction Adj Bare Steel Amort & Cost of Removal		82,916	77,189	37,350	78,908	71,812	81,198	82,192	82,192	125,393	153,757	168,355	157,852	1,199,113
0		0	0	0	0	0	0	0	0	0	0	0	0	0
Net Const. Cash Refunds/(Contributions)		32,146	32,146	32,146	32,146	32,146	32,146	32,146	32,146	32,146	32,146	32,146	32,146	385,756
BALANCE		(1,675,428)	1,580,141	280,547	124,206	(753,877)	(838,851)	386,743	446,706	(1,534,507)	(2,304,676)	(4,313,375)	(1,615,764)	(10,218,155)
Add Proceeds From Financing -SunTrust LOC (See Detail Below)														0
Proceeds from Water Sale & LWG				300,000										300,000
Less Tax on Gain of Sale Water & LWG														0
Add Proceeds from Financing - BOA LOC		(1,892,000)	(2,618,000)	3,066,000	(1,499,000)	2,622,000	1,726,000	(2,141,000)	536,000	200,000	2,200,000	4,500,000	1,500,000	8,202,000
Less LT Debt Principal Repayments						(1,409,000)								(1,409,000)
Less Loan Expenses (LT Debt)														0
Add Proceeds from Bond Issue														0
Less Loan Expenses (Bonds)														0
Add Proceeds from Equity Issue														0
Less Equity Issue Expenses														0
Less ST Investments														0
Cash Balance - Beginning Of Period		3,477,649	(89,778)	(1,125,637)	2,520,909	1,146,116	1,605,239	2,492,387	738,130	1,720,836	386,329	281,654	468,279	3,477,649
Cash Balance - End of Period		(89,778)	(1,125,637)	2,520,909	1,146,116	1,605,239	2,492,387	738,130	1,720,836	386,329	281,654	468,279	352,495	352,495
Customer Deposit - Annual Payments	445,578													
Line of Credit - Bank of America	12,000,000	12,000,000	12,000,000	12,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	26,000,000	26,000,000	26,000,000
Interest on LOC	0.10%	1,000	1,000	1,000	1,300	1,300	1,300	1,300	1,300	1,300	1,300	2,200	2,200	16,500
Notes Payable Balance - BOA	11,122,000	9,230,000	6,614,000	9,680,000	8,181,000	10,803,000	12,529,000	10,388,000	10,924,000	11,124,000	13,324,000	17,824,000	19,324,000	19,324,000
Interest on Borrowings	3.86%	32,700	25,500	26,200	28,700	30,500	37,500	36,900	34,300	35,500	39,300	50,100	59,700	436,900
Unused Portion of LOC	878,000	2,770,000	5,386,000	2,320,000	6,819,000	4,197,000	2,471,000	4,612,000	4,076,000	3,876,000	1,676,000	8,176,000	6,676,000	6,676,000
Interest on Unused Portion of LOC	0.25%	400	800	600	1,000	1,100	700	700	900	800	600	1,000	1,500	10,300
Additional LT Debt Balance	14,990,000	14,990,000	14,990,000	14,990,000	14,990,000	14,990,000	14,990,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	
Interest On additional LT Debt	6.85%	85,600	85,600	85,600	85,600	85,600	85,600	85,500	85,500	85,500	85,500	85,500	85,500	1,026,600
Bond	0	0	0	0	0	0	0	0	0	0	0	0	0	
Interest on Bond	5.50%	0	0	0	0	0	0	0	0	0	0	0	0	0
Private Activity Bond - Used	14,000,000	14,000,000	14,000,000	14,000,000	14,000,000	14,000,000	14,000,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	
Interest On Private Activity Bond	4.90%	57,200	57,200	57,200	57,200	57,200	57,200	57,100	57,100	57,100	57,100	57,100	57,100	685,600

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Docket No. 080366-GU
Witness: COX

FLORIDA PUBLIC UTILITIES COMPANY
CASH PROJECTION
BUDGET 2009

TOTAL CONSOLIDATED

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Operating Revenues		14,502,325	12,348,449	11,699,051	10,502,512	9,703,120	9,881,162	9,826,558	9,994,127	9,439,287	9,838,531	11,212,524	14,031,378	132,979,023
Fuel Revenue & Pass-thrus		(8,268,709)	(6,997,923)	(6,810,286)	(6,040,963)	(5,415,481)	(5,664,288)	(5,686,443)	(5,801,240)	(5,260,793)	(5,770,379)	(6,810,945)	(8,726,666)	(77,254,116)
Gross Profit		6,233,616	5,350,526	4,888,765	4,461,548	4,287,638	4,216,875	4,140,114	4,192,887	4,178,495	4,068,152	4,401,579	5,304,713	55,724,908
Other Income - Net (excl. taxes & int cap)		54,652	96,608	71,531	91,774	25,338	80,514	43,937	80,809	54,794	26,220	68,943	57,707	752,627
Total		6,288,268	5,447,135	4,960,296	4,553,322	4,312,976	4,297,389	4,184,051	4,273,696	4,233,289	4,094,371	4,470,522	5,362,419	56,477,735
DEDUCTIONS:														
Operation & Mince Excl Fuel etc		3,472,609	2,980,631	2,723,579	2,485,572	2,388,685	2,349,262	2,306,498	2,335,898	2,327,880	2,266,407	2,452,163	2,955,307	31,044,692
Non-Cash O&M (Storm Resv)		(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(8,333)	(100,000)
Income Taxes Paid					696,955		696,955			696,955		0	696,955	2,787,820
Taxes Paid - Other		251,162	13,700	155,337	96,966	64,617	83,646	254,658	94,094	51,616	207,630	2,022,300	11,602	3,307,740
Interest On Long - Term Debt						685,754	363,200					617,184	363,200	2,029,338
Interest on Additional LT Debt	6.85%	256,500			256,500			256,500			256,500			1,026,000
Interest on Environmental Expenditure		0	0	0	0	0	0	0	0	0	0	0	0	0
Interest on Private Activity Bond	4.90%					342,400						342,400		684,800
Interest on LOC		87,307	82,970	77,586	77,958	84,743	89,290	60,510	34,413	36,708	40,360	49,327	55,356	776,528
Other Interest Payments		0	0	0	229,500	229,500	0	0	0	0	0	0	0	459,000
Payment Of Environmental Clean Up		181,125			181,125			181,125			181,125			724,500
Dividends Paid - Preferred		7,125	0	0	7,125	0	0	7,125	0	0	7,125	0	0	28,500
Dividends Paid - Common		717,000	0	0	719,000	0	0	732,000	0	0	897,000	0	0	3,065,000
Proceeds Form Sale - Common Stock		(164,807)	0	0	(87,459)	0	0	(171,000)	0	0	(84,111)	0	0	(507,378)
Pension Contributions									1,790,772					1,790,772
TOTAL DEDUCTIONS		4,799,887	3,069,173	2,948,169	4,654,909	3,787,366	3,574,020	3,619,083	4,246,844	3,105,026	3,763,909	5,475,040	4,074,087	47,117,511
BALANCE		1,488,381	2,377,962	2,012,128	(101,587)	525,610	723,368	564,968	26,852	1,128,263	330,463	(1,004,518)	1,288,332	9,360,224
Increase (Decrease) in Cash Due to Fluctuation in Certain Assets & Liab.		.	.	.	.	-	.	.	.	-	.	.	.	.
Construction Requirements (including AEP)		810,019	810,946	1,126,442	959,514	987,222	885,188	743,734	1,073,005	1,106,862	1,795,352	1,452,265	1,475,051	13,227,600
Construction Adj Bare Steel Amort & Cost of Removal		83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	1,000,000
0		0	0	0	0	0	0	0	0	0	0	0	0	0
Net Const. Cash Refunds/(Contributions)		33,426	33,426	33,426	33,426	33,426	33,426	33,426	33,426	33,426	33,426	33,426	33,426	401,110
BALANCE		561,603	1,450,257	766,926	(1,177,861)	(578,371)	(278,578)	(295,525)	(1,162,911)	(95,358)	(1,581,647)	(2,573,542)	(303,478)	(5,268,486)
Add Proceeds From Financing -SunTrust LOC (See Detail Below)														0
Proceeds from Water Sale & LWG				300,000										300,000
Less Tax on Gain of Sale Water & LWG														0
Add Proceeds from Financing - BOA LOC		(600,000)	(1,500,000)	(1,000,000)	1,200,000	2,000,000		(13,500,000)	1,000,000	100,000	1,700,000	2,600,000	200,000	(7,800,000)
Less LT Debt Principal Repayments						(1,409,000)								(1,409,000)
Less Loan Expenses (LT Debt)														0
Add Proceeds from Bond Issue														0
Less Loan Expenses (Bonds)														0
Add Proceeds from Equity Issue								15,000,000						15,000,000
Less Equity Issue Expenses								(900,000)						(900,000)
Less ST Investments														0
Cash Balance - Beginning Of Period		352,495	314,097	264,354	331,280	353,420	366,049	87,471	391,946	229,034	233,676	352,029	378,487	352,495
Cash Balance - End of Period		314,097	264,354	331,280	353,420	366,049	87,471	391,946	229,034	233,676	352,029	378,487	275,009	275,009
Actual Cash Balance														
Customer Deposit - Annual Payments	456,945													
Line of Credit - Bank of America	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000
Interest on LOC	0.10%	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	26,400
Notes Payable Balance - BOA	19,324,000	18,724,000	17,224,000	16,224,000	17,424,000	19,424,000	19,424,000	5,924,000	6,924,000	7,024,000	8,724,000	11,324,000	11,524,000	11,524,000
Interest on Borrowings	5.30%	84,000	79,400	73,900	74,300	81,400	85,600	56,000	28,400	30,800	34,800	44,300	50,500	723,600
Unused Portion of LOC	6,676,000	7,276,000	8,776,000	9,776,000	8,576,000	6,576,000	6,576,000	20,076,000	19,076,000	18,976,000	17,276,000	14,676,000	14,476,000	14,476,000
Interest on Unused Portion of LOC	0.25%	1,500	1,700	1,900	1,900	1,600	1,400	2,600	4,100	4,000	3,800	3,300	3,000	31,000
Additional LT Debt Balance	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	14,975,000	
Interest On additional LT Debt	6.85%	85,500	85,500	85,500	85,500	85,500	85,500	85,500	85,500	85,500	85,500	85,500	85,500	1,026,000
Bond	0	0	0	0	0	0	0	0	0	0	0	0	0	
Intererst on Bond	5.50%	0	0	0	0	0	0	0	0	0	0	0	0	0
Private Activity Bond - Used	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	13,975,000	
Interest On Private Activity Bond	4.90%	57,100	57,100	57,100	57,100	57,100	57,100	57,100	57,100	57,100	57,100	57,100	57,100	685,200

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Docket No. 080366-GU
Witness: COX

DIRECT TESTIMONY

ROBERT J. CAMFIELD

INFLATION ESCALATION FACTORS FOR DETERMINATION OF REVENUE REQUIREMENTS

of

FLORIDA PUBLIC UTILITIES COMPANY

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

A. My name is Robert Camfield. I serve in the capacity of Vice President with Christensen Associates Energy Consulting, LLC. My business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. What is the purpose and scope of your testimony?

A. My testimony provides estimates of expected inflation, which are the basis for escalation factors used to determine revenue requirements of Florida Public Utilities Company ("Company") in the current docket.

Q. Have you provided testimony in the immediate docket?

A. Yes. I have collaborated with Witness Cox to provide cost of capital estimates and rate of return recommendations on behalf of Florida Public Utilities Company. That testimony is also included in the filing by the Company in the immediate docket.

Q. What are the timeframes and cost areas covered by the escalation factors?

A. The inflation estimates and resulting escalation factors, as incorporated into the Company's projections of revenue requirements, cover the second half of 2008 and the forward-looking test year, 2009. Cost escalation attributable to inflation affects both rate base and operating expenses, and the Company utilizes a factor to account for the steadily rising costs of inputs used to provide services. The inflation factor is estimated for each of these two timeframes, the second half of 2008 and for 2009.

The Company's inflation factor represents general inflation and is developed using three methods including model-base estimates and surveys of expected inflation. The third approach derives the rate of expected inflation from the difference in yields to maturity on comparable risk debt securities. These three methods are used to develop five estimates of inflation covering the general economy for 2008 and 2009, as follows:

- Model-based estimates of inflation developed by Moody's Economy.com, a well-known U.S. forecast service.
- Consensus view of forecast services, as compiled by the Federal Reserve Bank of Philadelphia in its Survey of Professional Forecasters.
- Calculated interest rate spread between the nominal and inflation-adjusted securities (Treasury Inflation Protected Securities, or TIPS), for U.S. government securities.
- Adjusted interest rate yield spread, as estimated by the Federal Reserve Bank of Cleveland. The adjustment to the nominal and TIPS yields accounts for changes in liquidity preferences of investors, referred to as liquidity premium.

- Survey of consumer expectations, conducted by the University of Michigan Consumer Survey Service.

Model-Based Estimation. Economy.com is a longstanding forecast service with major offices in the United States, United Kingdom, and Australia as well as branch offices in Europe, Asia, and North America. With clients that number over 500, Economy.com offers a variety of forecast services, including data banks and in-depth, focused services on various aspects of the U.S. and world economy of particular interest including, most recently, financial services and housing. For the U.S., Economy.com employs a large scale macro economic model of the U.S. economy, utilizing simultaneous equation systems that include several hundreds of equations. Model solutions and forecasts have quarterly frequency for several years forward, and then annual frequency covering a twenty-five-year outlook.

Consensus View of Forecasters. The Survey of Professional Forecasters ("SPF"), as conducted by the Philadelphia Federal Reserve Bank, provides the consensus view of U.S. forecasters regarding the general outlook for the U.S. economy. Private forecast services can be highly specialized, focusing on specific areas of the U.S. Often, the underlying models are systems of equations solved simultaneously but, unlike the large scale macroeconomic models of, say, Economy.com, consist of much more limited sets of equations. In virtually all cases, the starting point is a U.S. macroeconomic forecast that includes the main headline indicators such as real economic output, personal income, employment, and price levels among others. Blue Chip Economic

Indicators also gathers, at regular intervals, via surveys, the consensus view of forecast services.

Yield Spread Between Nominal and Inflation-Protected Securities. The expected rate of overall price inflation can be inferred by the interest rate spread between nominal U.S. government long-term securities—*i.e.*, bonds of the U.S. Treasury—and the corresponding yield on U.S. TIPS. Because TIPS insulate investors from inflation, and because U.S. securities are essentially risk free, the yields on TIPS constitute a good estimate of the risk-free real returns to capital. Because nominal Treasury securities are of equivalent risk but do not insure investors against the loss of purchasing power due to inflation, the yield difference provides an estimate of inflation expectations harbored by investors. We derive two estimates of investor expectations of inflation, including 1) an unadjusted yield difference, and 2) an adjusted yield spread that incorporates liquidity premia attributable to *on-the-run* and *off-the-run* yield differences, as estimated historically.

Consumer Expectations of Inflation. With regular frequency over decades, the Survey Research Center ("SRC") of the University of Michigan has conducted surveys of households that cover a variety of measures of consumer sentiment, including expected increases in prices. The survey is well known, widely used by public and private entities (including forecast services) and is often referenced in news media. We incorporate the SRC survey results regarding household expectations of the annual rate inflation for 2008, which was 3.90%.

The Company's projected inflation factor for the latter half of 2008 and 2009 is the average of the five measures (sources) of expected inflation identified above, for each of these two years. The result of this broad-based approach to determining expected inflation is the basis for the Company's inflation factor, as presented in the following table.

EXPECTED INFLATION FOR 2008 AND 2009 (%)

Year	Forecast of Economy.com (August '08)	Philadelphia Fed Bank Survey of Professional Forecasters (August '08)	Treasury Yield Spread, Nominal - TIPS	Cleveland Fed Bank, U.S. Treasury Yield Spread, Adjusted Nominal -TIPS (July '08)	University of Michigan, Survey of Consumer Expectations (February '08)	Average
2008	4.17	4.30	N/A	N/A	3.90	4.12%
2009	2.50	2.40	3.13	2.95	N/A	2.74%

As shown, the expected rate of inflation is significantly higher in 2008 than 2009. The comparatively high inflation in 2008 is largely attributable to the approximately 60% rise in the wholesale prices for primary fuels during the first half of 2008. The impacts of fuels on general inflation are manifested with a lag of several months; hence, the upward price pressure caused by high fuel prices is likely to be greatest during the third and fourth quarters of 2008, while also reaching into early 2009. For 2009, price inflation is expected to return to the typical pattern observed over recent years. The overall price level for the U.S. economy has escalated 2.0 – 3.0% annually since 1998.

Q. Would you please summarize the results of your analysis of inflation expectations and the projected cost escalation factor proposed by the Company?

A. The analysis utilizes three methods including model-based estimates of price changes, surveys of expectations, and inferred inflation from yields on U.S. treasury securities.

The analysis suggests that the overall rate of inflation will increase during the second half of 2008 to 4.12%, which is substantially above the rate of inflation for 2007. This is an exceptionally high rate of price inflation when gauged with reference to the moderate rates of inflation over recent years, and is largely a consequence of the unexpectedly steep increases in primary fuel prices during 2007, continuing well into 2008. In contrast, the rate of inflation for 2009 will likely slow, with overall prices expected to rise 2.74% from the price level of 2008.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY
OF
MARC S. SEAGRAVE

IN

FLORIDA PUBLIC UTITITIES COMPANY
DOCKET NO 080366-GU

IN RE: PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY
FOR A NATURAL GAS RATE INCREASE

Q. Please state your name, affiliation, business address and summarize your academic background and professional experience.

A. My name is Marc S. Seagrave. I am currently the Director of Marketing and Sales for Florida Public Utilities Company ("FPU" or "Company"). My business office is 401 S. Dixie Hwy, West Palm Beach, Florida 33401. I joined FPU in July 1999 as General Manager of FPU's wholly owned propane subsidiary, Flo-Gas Corporation. In February 2004 I assumed the Corporate position of Director of Marketing and Sales. My work experience at FPU includes managing all aspects of the marketing and sales department, to include corporate communications, electric and natural gas energy conservation programs, natural and propane gas sales and merchandising. I am responsible for budgeting natural and propane gas revenue, electric and natural gas energy conservation revenue and all expense projections related to sales, merchandising, conservation and communications. Prior to FPU, I was employed by Tri-County Gas as a District Manager and ultimately advancing to General Manager from November 1994 until June of 1999. Prior to my employment with Tri-County Gas, I was employed by Tropigas/Petrolane/Amerigas through various acquisitions from November 1988 until October 1994 as a District Manager and Area Manager. Prior to Tropigas, I was employed by Florida Public Utilities where I started my utility career in the Installation and Maintenance Department in February 1986. I also served in the United States Army and Army Reserve as a Military Police Officer from 1983 until I retired in the position of Sergeant Major in 2004. I received my Bachelor of Transportation Logistics from the United States Army in 2002.

Q. Have you testified before the Florida Public Service Commission in previous cases?

A. Yes. I was involved in the Company's 2004 natural gas rate case Docket # 040216-GA and I have testified on behalf of the Company on all electric conservation filings starting with Dockets 040002-EG and 040004-GU respectively. Most recently, I testified before the PSC in support of Docket No. 080072-GU; Residential Standby Generator Rate. I have also made presentations before the Commission in workshops and agendas.

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

A. I am responsible for preparing MFR Schedule E-3 and Schedules I - 1-4. I also support information presented in Schedules C-5 and G-1 (B-10).

Q. Describe what Florida Public Utilities current Area Expansion Program (AEP) is and how it is used.

A: FPU extends its facilities to provide service in accordance with the provisions of Rule 25-7.054 Florida Administrative Code.

The rule requires extensions to be made at no cost to the customer when the capital investment necessary to extend the Company's facilities to provide service is equal to or less than the maximum allowable construction cost. The maximum allowable construction cost (MACC) is defined as being an amount equal to four times the estimated gas revenues which includes customer charge revenue, derived from the facilities less the cost of gas.

In the event the required capital investment cost exceeds the MACC, the Company requires the customer(s) to make a non-interest bearing advance in aid of construction in the amount equal to the difference provided that:

1. At the end of the first year the Company shall refund to the customer(s) paying the advance in aid of construction an amount equal to the excess, if any, of the MACC calculated using actual gas revenues, less actual cost of gas, over the MACC used to determine the amount of the advance in aid of construction.
2. For each additional customer taking service at any point on the extension within a period of five years from the date of construction, the Company shall refund to the customer that paid the advance in aid of construction an amount by which the MACC for the new customer exceeds the cost of connecting the customer, provided that an additional main extension shall not have been necessary to serve the additional customer.

The Area Expansion Program (AEP) is an alternate method of recovering capital construction costs that are in excess of estimated four –year base revenues that are to be derived from a defined main extension project. The AEP program allows the Company to add a surcharge that is billed by the therm to each participating customer until the excess construction costs to include the Company's allowable rate of return on the excess capital investment costs, is paid in full or maximum period of 10-years – whichever comes first.

Q. Explain why the Company seeks to modify its existing Area Expansion Program.

A. Florida Public Utilities (FPU) currently has 44 active AEP projects of which 38 are projected to have excess construction cost balances as of December 31st 2008. Due to unprecedented economic conditions that have halted the new construction housing market, negatively impacted businesses and the resulting voluntary conservation measures by FPU customers, the Company does not anticipate the excess construction cost balances of these projects to be recovered prior to the end of the 10-year allowable collection period. The Company therefore proposes to increase all existing AEP surcharge rates to $0.50 per therm. FPU's existing AEP was originally approved in 1995 (Docket # 941291-GU) and does not provide for an adjustment (true-up) mechanism at any point during the 10-year allowable collection period. Additionally, the program does not allow the AEP per therm surcharge rate to be changed once the in-service date has been established. The Company has conducted an analysis of all 44 active AEP projects. The analysis showed that without an adjustment to the per therm surcharge, the un-recovered excess construction costs at the end of the 10-year collection period of each project, in total, will exceed $4,000,000. It is the Company's intent to increase the surcharge rate for all existing 'recalculated' projects to $0.50 per therm, which will lower the projected un-recovered excess construction cost balances to approximately $2,400,000. The excess construction cost balance will be transferred to the appropriate plant account increasing rate base as filed with the current rate proceeding.

Q. How does FPU intend to revise its Area Expansion Program (AEP)?

A. Florida Public Utilities (FPU) current Area Expansion Program (AEP - Docket No. 941291-GU) has been in effect for nearly 14-years. Based on the experience of managing 45 AEP projects since the inception of the current program, FPU has determined that a new program is warranted.

<u>The primary elements of the proposed AEP are as follows:</u>

1. The new AEP proposed by the Company provides for determination of a specific fixed dollar surcharge applicable to each designated expansion area by class of customer, it is calculated by a formula based on the amount of excess capital investment required;
2. The Company's authorized rate of return approved by the Commission as a result of the present rate proceeding;
3. The projected sales to be made on the extension;
4. The time period not to exceed 10-years the surcharge is applicable;
5. A provision to adjust up or down the fixed dollar surcharge based on actual sales and actual excess construction costs at the end of the fifth year following the in-service date of an AEP project;
6. There will be a refund of any revenues in excess of the projected surcharge total to all existing customers in the AEP area if the revenues collected exceed the estimated AEP projection;
7. Any un-recovered excess construction costs left over at the end of the 10-year maximum allowable recovery period will be transferred to the Company's rate base and the AEP project retired.

<u>The primary differences between the current AEP and the proposed AEP are as follows</u>:

1. The current surcharge method is calculated by dividing the estimated excess construction costs for a project by the estimated annual therm usage per customer by customer class to determine the per-therm billable surcharge. The new AEP program will utilize the same process to determine the surcharge revenue requirement by customer however the surcharge will be billed based on a fixed dollar charge per premise rather than a per therm charge. The cost to the customer will change from the current methodology but the risk element and the fairness issue will be addressed.

Discussion:

- <u>Risk reduction</u>: A fixed surcharge removes risk associated with under or over-estimating a customer's anticipated use of gas their gas equipment. Currently, if the Company over-estimates customer usage, the surcharge is not sufficient to recover excess construction costs within the 10-year allowable collection period.
- <u>Fairness element</u>: The current program places an unfair burden on certain customers who use more gas than those who have very low or no gas use. Those very low users pay much less for having the same access to the facilities installed. A user that installs multiple non- standby gas appliances is impacted to a much greater extent than a customer who installs a standby natural gas generator that is used rarely if ever at all.

The new program would require both customers cited in this example to pay an equal fixed dollar surcharge for the same access to the facilities.

2. The current AEP does not allow for the Company to make adjustments to the surcharge based on actual excess construction costs (ECC) and or AEP surcharge estimates versus actual surcharge revenue collected at any time during the 10-year allowable collection period. The new program calls for an adjustment to the fixed dollar surcharge be made, upward or downward, following the fifth year of the in-service date of the project.

Discussion:

- The adjustment is a true-up that takes into account the actual excess construction costs following the actual extension of facilities compared to what was originally estimated and it takes into account the actual surcharge revenue collected compared to what was originally estimated. FPU has historically been very accurate in estimating excess construction costs (within approximately 5% of actual) however customer conservation, economic conditions, slower than anticipated development and higher efficiency appliances have all contributed to making the estimation of revenues more difficult to project. A fixed dollar surcharge ensures that the collection of the required revenue to offset the excess construction costs will be more consistent and fair to the customers benefiting from the main expansion. The adjustment following the fifth in-service year, either up or down based on the actual

ECC and revenues generated will result in much more accurate billings for the customer.

3. Similar to how non-recovered excess construction costs are administered following the allowable 10-year collection period, the Company will transfer all un-recovered excess construction costs to the applicable capital plant construction account.

SUMMARY

The AEP surcharge option for funding main & service extensions allows customers access to natural gas. The Company's position is that the current AEP has provided many opportunities for customers to benefit from the extension of natural gas facilities without making an upfront CIAC. The actual performance of the AEP projects since the inception of the current approved program has been mixed at best. The changes necessary to make the new program more beneficial to customers and the Company have been stated as converting from a per therm surcharge to a fixed dollar surcharge; and true-up (an up or down adjustment to the fixed dollar surcharge) at the half way point following year five of the 10-year allowable collection period.

Q. Why does FPU propose a Research and Development Program?

A. Florida Public Utilities (FPU) proposes to budget $50,000 annually to fund a R&D program to be utilized to develop new and emerging uses for natural gas, processes that will enable the Company to sustain and enhance customer service and to increase customer and employee safety. These funds would be used for capital and expense projects outside of any approved natural gas energy conservation program.

FPU intends to contribute to studies that support new natural gas technologies that support bringing to market natural new types of gas utilization equipment such as residential and fleet natural gas fueling systems; desiccant dehumidification systems and solar thermal water heating systems that are coupled with tankless water heating as a back-up.

FPU intends to play an integral role in making natural gas available for operators of vehicle fleets and individual customers who wish to use natural gas as a fuel to get to and from work. The technology is available but not widely used and is currently cost prohibitive to most consumers. FPU will use money budgeted for R&D to assist in the funding necessary to develop natural gas fuel and compressor systems that will make the systems more affordable and much more available to the average customer. The Country has very challenging times ahead in the area of energy; there has never been a more important time than now to develop new technology that will bring enhanced value to those who need it most, our customers. There is a clear and immediate need to reduce our dependency on foreign oil. Natural gas will play a key role, particularly in the vehicle fuel market but more research and development is necessary to make fuel systems more affordable and widely available. Developing technology that will provide customers with alternate forms of energy using appliances and equipment powered by natural gas is not only socially responsible, it reduces our nation's dependency on foreign oil. It is also critical that we continue to advance and improve safety and reliability of our natural gas systems, equipment and customer protection measures. For the reasons stated, FPU needs to fund R&D programs.

Q. Why does FPU seek recovery of expenses related to its membership with the Council for Responsible Energy?

A. FPU has joined with and participates on the Council for Responsible Energy (CRE). The CRE grew out of what was initially known as the 'Green Team' who's original members included AGL, TECO, Piedmont, Alagasco and Mobil Gas. The team formed as a collaborative effort to develop a common natural gas message, graphic elements and collateral materials for an industry-wide outreach plan based around the ecological advantages of using natural gas as a preferred energy source.

Even prior to the CRE being formed, the Green Team selected through an extensive RFP process the advertising agency Porter Novelli who is widely acclaimed for their high quality work. Porter Novelli is well known in our industry for the work they did for the highly successful NPGA national advertising campaign centered around the 'Energy Guys' commercials we've all seen on TV.

In short, the CRE is making a strong effort to develop a national brand for natural gas (Comfortable – Responsible) that will tout all the benefits and positives of natural gas, most notably the 'green' aspects of low carbon emissions. With all the attention being placed on natural gas by the T.B. Pickens plan, natural gas as a vehicle fuel, and as an offset to power plan construction, this collaborative effort is one that I believe will bring a high value for every dollar we invest as a member.

The cost for our participation is $0.15 per residential meter ($0.15 x 47,224 = $ 7,083.60) annually which is a relatively low cost for the benefits the collaborative effort brings. We will have access not only to the marketing materials produced; we will have full use of the logo and all the research and tools such as the ESC appliance carbon calculator program. More information may be found at www.southerngas.org (SGA website) under the 'Marketing' tab – Green Team.

Q. Why does the Company forecast Sales Expense to increase in 2009 compared to 2007 and 2008?

A. Due to the slowing economy and the housing market, FPU did not replace two marketing sales positions during the 2007 – 2008 calendar years. With the slow down, FPU's base revenue decreased at the same time, therefore it was determined that the Company would put off replacing the positions lost to attrition. The tightening of the economy slowed sales and customer growth which in turn decreased sales expenses to include miscellaneous piping expense and sales commissions.

Starting in 2009, the Company intends to replace one of the two open positions as our marketing efforts are being concentrated in areas that provide the Company the best opportunity for new growth. FPU is placing a high emphasis on extending natural gas facilities and services in and around existing neighborhoods in order to maximize our penetration in areas that do not require extensive main extensions.

FPU also anticipates the increasing demand for natural gas as a vehicle fuel and as such it will be necessary to have trained individuals prepared to meet our customer's needs. The outreach into existing neighborhoods takes more time and effort from a sales perspective than a new master planned development. The effort is more labor intensive but the result will provide potential customers who are near natural gas mains the means to have access to low cost, clean, efficient and domestically produced energy which is in high demand.

Q: Why does FPU intend to establish a commercial generator-only rate structure?

A: Florida Public Utilities (FPUC) intends to establish a commercial generator-only rate for existing and new customers who are either using or will use natural gas for the purpose of fueling a generator-only. The purpose of the new is to implement a rate structure which enables the Company to recover the costs associated with providing service to commercial generator-only customers very similar to the approved residential generator-only rate approved effective October 1st, 2008 under docket # 080072-GU.

Historically, FPUC has received requests from potential customers interested in installing a standby generator as their sole gas appliance. These requests increased significantly after the 2004 hurricane season. The generators are operated during periods of power interruption and minimally – if at all- during other periods. Currently, FPUC provides the service at commercial rates which include a $15.00 per month customer charge and a non-fuel Energy Charge of $.32107 cents per therm.

Fuel is provided at the Company's Purchase Gas Adjustment rate in effect for the month of service.

The current rates are designed to recover the majority of the Company's costs from the non-fuel Energy Charge based on a customer's actual monthly gas usage. However, unlike commercial customers who have and use other natural gas appliances and equipment, commercial generator-only customers may only use approximately 1,900 cf/hour while operating on a 15-minute weekly maintenance cycle and thus do not use gas on a regular basis and unlike service to other customers, there is no assurance that the Company will be able to recover the cost to serve such customers.

To mitigate this situation, FPUC is proposing to establish a new tariff schedule for standby generator-only customers (Commercial Standby Generator Service (CS-GS). All existing and future commercial generator-only customers would be served under this schedule. The monthly minimum bill for CS-GS customers would be proposed $39.52 Customer Charge. In the event a generator-only customer's actual gas use during any month exceeds 36.31 therms, the therms in excess of 36.31 therms would be billed at the GS-1 commercial service rate of $0.41265 per therm. The charge for any fuel used by generator-only customers would continue to be billed at the Company's prevailing Purchase Gas Adjustment rate. The proposed CS-GS rate schedule would enable the Company to recover its costs to provide service to commercial generator–only customers.

Q. Why does FPU project an increase in Piping and Conversion Expense beginning in 2009?

A. Due to the unprecedented slow down in the economy and the new construction housing market, FPU is concentrating its efforts to attract new customers on or near existing natural gas mains. The Company will focus its marketing efforts to encourage potential residential and commercial to convert from electric to highly efficient natural gas appliances such as the tankless water heater. FPU will heavily promote conversion to tankless water heaters beginning in 2009 through a variety of marketing programs. FPU expects to add 200 new highly efficient tankless water heaters per year to its customer base at an expense of $350 per installation. It is expected that this program will add a moderate to significant number of customers to FPU's current customers at a relatively low capital investment cost due to adding new customers close in proximity to existing natural gas facilities. FPU will amortize costs associated with the conversions over a 5-year period. It is expected that there will be strong participation in the electric tank to natural gas tankless program and as such it is forecast that will be an increase of $70,000 per year to piping and conversion amortization expense of which approximately $14,000 will be expensed to the Company's miscellaneous piping and conversion account. The $14,000 increase in annual expense will be offset by a reduction of approximately $46,916 due primarily to the completion of the amortization of leased water heaters that were acquired with the acquisition of Atlantic Utilities.

Q: Does this conclude your testimony?

A: Yes

DIRECT TESTIMONY

OF

DONALD E. KITNER

IN

FLORIDA PUBLIC UTILITIES COMPANY

DOCKET NO 080366-GU
IN RE: PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY
FOR A NATURAL GAS RATE INCREASE

Q. **Please state your name, affiliation, business address and summarize your academic background and professional experience.**

A. Donald E. Kitner – General Manager of Central Florida for Florida Public Utilities Company (FPU). My business office is 450 S. Hwy 17-92, DeBary, Florida 32713. In June of 1971 I began working with Equitable Gas Company in Pittsburgh, Pennsylvania and left in February 1990 while in the position of Supervisor of Construction and Maintenance. I was involved in budgeting, construction operations and maintenance activities while at Equitable Gas Company. I joined FPU in February 1990 as Installation & Maintenance Superintendent in the West Palm Beach Division and received my Bachelor of Human Resource Management in 1992 from Palm Beach Atlantic College. In January 1997 I assumed the position of General Manager of FPU's Central Florida Division. My work experience at FPU includes all aspects of budgeting, customer service, engineering, construction, marketing, operations and maintenance in the Central Florida Division.

Q. **What is the purpose of your testimony?**

A. I will address the operations of the natural gas division and explain the adjustments that are being proposed for operational reasons. I also support the development of the Minimum filing Requirement Schedule E-3, E-7 and I-1 thru I -3.

Q. **Have you presented testimony before the Florida Public Service Commission?**

A. Yes. I filed testimony in Docket No.040216-GU, the last base rate proceeding for the Company.

Q. **In the Order approving that increase the Commission made an adjustment for inactive service lines. Has the Company addressed inactive service lines identified in the 2004 rate proceedings addressed?**

A. Yes, all of the inactive service lines identified in the 2004 rate proceedings were either abandoned as required or reactivated. A couple of service lines that were reactivated have subsequently been disconnected for one reason or another. Presently the Commission's Bureau of Safety has granted a moratorium on abandoning inactive service lines while the industry conducts a study regarding the five year abandonment requirement.

Q. **Could you briefly describe the quality of service that you provide customers in your service area?**

A. For many years, both divisions have provided reliable low cost service to the customers within our service territory and have relatively few customer complaints. FPU has consistently had some of the lowest purchased gas adjustment costs in Florida. FPU has not experienced an outage that falls under the reporting requirements of the commission's Bureau of Safety.

Q. **Do you have any way in which you measure the quality of service that you offer?**

A. We measure our service based on cost, reliability and customer service. As mentioned above, we consistently rank favorably to other utilities in the area. This rate proceeding will have a direct effect on both cost and reliability factors. Although costs will increase, FPU will still provide fair natural gas rates to customers while allowing for continued focus on increasing reliability above current levels. Indirectly customer service will be improved based on improvement in reliability.

Q. Please identify the new positions in the Office and Engineering Departments and explain their functions.

A. The following positions are being added: one (1) Administrative/Analyst positions, one (1) AM/FM Coordinator for the South Florida Division and one (1) AM/FM Administrator for the gas divisions The Administrative/Analyst position for Central Florida Operations is necessary to maintain acceptable levels of service to our customers and provide the division with current analysis of various projects and activities ensuring cost effectiveness of office functions, new construction and maintenance activities. Up to now management has attempted to fulfill these duties, with considerable hours worked beyond a normal workday, but does not have the time to continue and complete the necessary analysis' in the manner and extent required. The natural gas portion for the 2009 projected test year is $43,300 for the Administrative/Analyst positions.

The AM/FM Coordinator will be utilized in the South Florida Division to bring the as-builts up to date in the electronic mapping system. There currently exists a considerable backlog of as-built construction drawing that have yet to be added to the mapping system. The AM/FM Administrator position is necessary to administer and maintain the electronic mapping system and compliance records for the natural gas distribution systems. The AM/FM system was purchased within the last two years and is now on-line and readily available to the various gas departments. This position will also provide updates to the technology for the system and routine training for the end users. The natural gas portion for the projected 2009 test year is $93,500; $50,000 for the AM/FM Administrator and $43,500 for the AM/FM Coordinator.

Q. What is the purpose of the GPS, Dispatching and Navigational System?

A. The Company purchased and implemented a GPS Tracking, Navigating, and Dispatching system between October and November 2008. The GPS, dispatching and navigational system will allow dispatchers and management to be aware of the exact location of all Company vehicles, at all times. Dispatchers will be afforded the ability to dispatch the closest qualified vehicle to customer requests for service or leak calls improving the Company's response time and overall customer service. The navigational segment of the system will provide the vehicle's operator with clear concise directions to their next call with the most direct route and shortest timeframe. This system will enable management to closely monitor crew activities and locations to optimize crew utilization. The cost indicated is the actual amount, by contract, from the vendor. Allowances were made for allocations to Company business units other than natural gas. A total of 154 vehicles will be equipped with this system. The natural gas portion for the 2009 projected test year is $60,900.

Q. What is the purpose of Operational, Technical, Safety and Leadership Training?

A. The Company's intent is to improve the level of service to its customers by participating in various industry opportunities presently available. The Company does not want to become stagnant in its practices and procedures, but to stay current in the industry's best practices and most cost effective methods. Training will include but is not limited to construction practices, customer service methods, operations and maintenance activities, safety practices, Operator Qualification / Integrity Management Seminars and leadership training. A list of training opportunities and seminars the Company intends to participate and attend is attached as Exhibit DK-1. The amount added, as an Over/Above Expense adjustment, to the 2009 projected test year is $102,140.

Q. What is the purpose of the web based operator qualification training?

A. The Federal Office of Pipeline Safety and the Commission's Bureau of Safety have mandated Operator Qualification Training for all employees performing covered activities associated with natural gas operations. These activities include all aspects of installing, operating, maintaining and repairing natural gas distribution facilities. The web based training is for the 'class room' portion of the training, including written testing which it tracks the progress and results of each employee individually. The web training covers the written requirements for Operator Qualification Training for all aspects of the Company's field employee's duties and responsibilities associated with installing, operating, maintaining and repairing natural gas distribution facilities. This is followed-up with in-field visual verification by a qualified individual certifying the employee's proficiency in their job tasks. The adjustment to the projected 2009 test year is $13,400 and is to recover the costs associated with the on-line training program, which is an annual cost and is based on actual cost projections provided from the vendor.

Q. Why is the bridge crossing repairs and maintenance necessary?

A. The Commission's Bureau of Safety has recommended extensive repair and maintenance activities on 14 bridge crossings. The cost associated with the repair and maintenance activities recommended is $105,000 which we anticipate amortizing over four years. These repair and maintenance activities are above and beyond the normal activities required on bridge structures. The Company received a proposal of $98,470 if completed in 2008. This estimate is expected to increase between 6% and 7% for 2009 which is when the work is anticipated to be completed. The increase to the 2009 projected test year for the bridge crossings repair and maintenance is $26,850.

Q. What is the sub-aqueous crossing inspection and intra-coastal crossing location?

A. We are required by governmental rules and regulations to inspect all sub-aqueous crossings once every five years. The Central Florida Division has one crossing and is asking for recovery of these expenses at a rate of one-fifth per year. This equals $600 per year based on a five year recovery. The South Florida Division has multiple sub-aqueous crossings and have their inspections equally spread over the five year period. The adjustment for the inter-coastal crossing location of $4,800 is for an unusual occurrence in that this is the first time the Company was required to provide any party an exact location of its sub-aqueous crossing for excavation purposes. The Army Corp of Engineers contracted a dredging company to dredge the intra-coastal channel in the New Smyrna Beach area. The Company had to provide an actual line location as required by the Underground Facilities Damage Prevention and Safety Act, Chapter 556 Florida Statutes which necessitated sub-contracting the line location to a qualified dive company. The recovery requested for the line location is for the actual cost associated with the physical line location.

Q. What are the SummerGlen adjustments?

A. The Company completed the conversion of approximately 517 homes in the SummerGlen community located in our West Florida Division from propane gas to natural gas on October 1, 2007. The historic year, 2007 was normalized for expenses related to the operational costs to service these new customers for administrative, customer service, marketing, operation and maintenance activities. We increased the projected 2009 expenses by $57,300 over the 2007 historic year.

Q. There is also an adjustment to replace vacant positions. Why is it necessary to replace the vacant positions?

A. In 2008 the Company attempted to reduce staffing levels, thru attrition, in an effort to control costs, in part due to the declining housing industry. However, the Company has determined to ensure proper levels of customer service, staffing levels need to be increased. In doing so the Company intends to replace two (2) marketing positions (1-Marketing Administrator and 1-Marketing Representatives), three (3) Installation and Maintenance Workers, three (3) Service Workers, two (2) Service Supervisors, one (1) Warehouse Worker and one (1) Senior Admin Distribution Clerk. The natural gas portion of the expense increase included in the 2009 projected test year is a decrease from the 2007 historical test year of $16,555 due to position vacancies. The adjustments for these positions are included in witness April Lundgren's testimony.

Q. What is the reason for additional expenses, over the 2008 level, for line locations?

A. Underground facility owners are required by law to locate their facilities, at no charge to the requestor, in areas of proposed excavation. The Company experienced an abnormally low number of requests in 2008 for line locations. The number of location requests, are expected to begin to return to normal levels in 2009 based on forecasted construction activities, particularly in the municipal road construction arena. South Florida Division will be slightly below the level received in 2007. The Company experienced three to four municipal road projects, per year, for the last several years. In 2009 and future years the number of municipal road construction projects is expected to more than double based on information received from local and state agencies and particularly in light of the State of Florida's announcement to speed up road construction. The expenses for 2009 are expected to be back to the levels experienced in 2007 in the Central Florida area and to a lesser degree in the South Florida area. The South Florida reduction for 2009 from the historic test year of 2007 is $75,000.

Q. Please explain why you are adding steel tubing to the bare steel replacement program.

A. The Commission's Bureau of Safety has strongly recommended the Company develop a steel tubing replacement program, to systematically replace steel tubing mains and services. Adding steel tubing to the bare steel replacement program will further improve the integrity and reliability of the Company's distribution system piping. The Department of Transportation, Pipeline and Hazardous Materials Safety Administration and the Commission's Bureau of Safety are both in the process of developing rulemaking to address distribution integrity management which should become law mid-2009 further emphasizes the need not only to continue the bare steel replacement program but to enhance this program to include steel tubing replacements. The increase to the 2009 projected test year for including the steel tubing program is $56,798 for a total annual recovery of $623,106 per year. The amortization period for this program would be extended from 50 years as approved in the 2004 rate proceeding to 60 years. The amortization schedule for the bare steel and steel tubing replacement program is included in witness Mesite's testimony.

Q. What is the purpose of the Municipal Road Projects and System Improvement program?

A. The Company installs its mains, for the most part, in public right-of-ways, as the cost associated with private easements is cost prohibitive.

Obtaining easements from adjoining property owners to facilitate an installation is not practical, very time consuming and costly to say the least. That is assuming adjoining property owners would be receptive in the first place. Therefore, installation in public right-of-ways is generally the most cost effective location for natural gas distribution systems. The governmental entity controlling the right-of-way, by permit, will allow natural gas facilities to be installed in their right-of-ways. There is a downside associated with utilizing public right-of-ways; that being if the governmental entity controlling the right-of-way undertakes a road improvement the Company is required, by conditions associated with the issuance of the permit, to relocate its facilities at its own expense if it conflicts with their road improvements. The Company works with governmental road project designers to minimize conflicts, however if the conflicts cannot be resolved by design criteria the Company is required to relocate its facilities, at its own expense. System improvements consist of replacing existing lines with larger facilities or installing facilities in new locations to support the existing or planned future load. The existing consumers benefit from additional customers to share the fixed costs associated with operating the existing distribution systems and the environment is positively impacted by reduced carbon emissions from coal and oil power plants. System improvements/expansions will also reduce the need for additional power plants and make natural gas available to more areas within the Company's operating regions. The Company has construction scheduled for municipal road projects presently identified and scheduled for construction next year as well as necessary system improvements totaling $1,741,319 for 2009. The Westward Expansion Phase III project includes $641,319 for system improvements (included in the $1,741,319 figure) to connect two dead end systems thereby improving system integrity and reliability and $700,000 for the revenue producing installation of which $341,961 will be covered by an AEP surcharge.

Q. What capital improvement projects are anticipated?

A. The Company's proposed capital improvement budget is for revenue and non-revenue producing projects. The revenue producing projects are based on my expert opinion and knowledge of projects presently in design and development stages with some funds for projects unknown at this time. Costs for these projects are based on Company labor and outside labor already under contract. The non-revenue producing projects are for employee safety (respirators, security cameras, squeeze-off tools), normal replacements (vehicles, air conditioners, roof sealing, welding machine, stopper equipment, line locators; due to increased down time and maintenance expenses, improvements to additional property purchased for customer and employee parking, system integrity (odorizer and relief for

2-gate stations) and additional equipment needed i.e., color printers for marketing activities, and various equipment for improvements to operations activities. Costs for these items were based on product knowledge, investigation and preliminary price quotes. The overall capital expenditures are consistent with historical levels with the exception of those detailed in the testimony for special items such as the bare steel and steel tubing replacement program and the municipal road projects and system improvements. The overall capital projects are necessary and appropriate.

Q. Explain the development of Schedule E-3.

A. The Company is proposing to increase its service charges for initial establishment of service, re-establishment of service, change of account, reconnection after disconnection for non-pay, bill collection in lieu of disconnection for non-pay, charge for customer who fail to keep a scheduled appointment, add a charge for temporary disconnection of service at a customer's request and to eliminate the processing fee associated with accepting credit or debit cards for customers who are paying their bill. The Company proposes adding the temporary disconnection charge at a customer's request to cover termite tenting of their house and other similar situations. A study was conducted, over the past three (3) years, of the number of requests and the costs associated with each aforementioned activity. During this study it was confirmed there was no material difference in costs with the connection and reconnection of the same account. It was also confirmed that there continues to remain a significant difference in the cost with the connection and reconnection of residential, general service and large volume service to continue with a separate customer charge for each class of service. During this study it was determined there was no material cost difference to justify two separate customer charges for the two general service categories. The Company is proposing the elimination of the fee for accepting credit and debit cards as these are now being processed by an independent third party. The Company proposes to continue charging a premium for same day requests and scheduled after hour requests. This practice covers the overtime costs associated with same day calls which routinely cause someone to work overtime to accommodate same day requests. The service schedule is normally booked for the day and any additional same day requests cause the servicemen to work overtime to complete the additional requests. Costs to perform these activities are detailed on MFR Schedule E-3.

Q. Explain Schedules I.

A. The Company experienced no interruption of service affecting the lesser of 10% or 500 or more customers – Schedule I-1. The Company was issued three (3) Notifications of Rule Violations, all of which were addressed immediately and one was withdrawn - Schedule I-2. The Company discovered a computer software issue in June 2008. This computer software issue precluded an accurate selection of meters that were due for periodic testing. Seven (7) - 250 cfh or less meters; 126 - 251 cfh thru 2500 cfh, and 34 over 2500 cfh meters were not tested within the timeframes prescribed – Schedules I-3. Once the computer software issue was discovered (June 2008) immediate corrections were made and a concerted effort is being made to test all meters identified. These meters, as detailed on Schedules I-3, that are out of test date have either been tested or will be tested by the end of 2008

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT DK-1

2009 TRAINING & SEMINARS

AVANTI TRAINING CENTER	
Basic Distribution; 4 day course – 4 attendees	$3,320.00
Regulator Training; 3 day course – 2 attendees	$1,420.00
Gas Valve Training; 3 day course – 4 attendees	$2,840.00
Advance Distribution: 3.5 day course – 2 attendees	$1,420.00
NATIONAL WELDING INSPECTION SCHOOL	
Welding Certification Inspection Class – 2 attendees	$5,000.00
SGA TRAINING	
Managing Natural Gas Emergency Workshop – 2 attendees	$3,200.00
Commercial & Industrial Marketing Conference – 2- attendees	$3,200.00
Commercial Food Service Marketing Conference – 2 attendees	$3,200.00
Pipeline Construction Workshop – 2 attendees	$3,200.00
Pipeline Repair Workshop – 2 attendees	$3,200.00
Operations and Marketing Conference and Expo – 2 attendees	$3,200.00
SGA Training Week – 2 attendees	$3,200.00
Distribution Operating Conference – 4 attendees	$6,240.00
Customer Solutions Conference – 2 attendees	$4,800.00
Distribution Operating Executive Roundtable – 2 attendee	$5,000.00
Operator Qualification – 1 attendee	$1,850.00

GAS TRAINING SERVICES

Gas Pipe Sizing – 14 attendees	$1,050.00
Emergency Response – 14 attendees	$1,050.00
Natural Gas Overview	$1,050.00
Intro to Natural Gas – 14 attendees	$1,050.00
Florida Fuel Gas Code – 14 attendees	$1,050.00

FNGA TRAINING

Annual Conference – 2 attendees	$1,600.00
Annual Distribution/Marketing Conference – 4 attendees	$3,200.00
Appalachian Measurement Course – 1 attendee	$1,800.00
Appalachian Underground Corrosion Course – 2 attendees	$3,600.00

GAS TECHNOLOGY INSTITUTE

Gas Distribution Engineering & System Planning – 2 attendees	$10,000.00
Distribution Integrity Management – 1 attendee	$4,000.00

VARIOUS TRAINING AND SEMINARS

International Builders Conference – 4 attendees	$4,000.00
Southeast Builders Conference – 4 attendees	$3,000.00
Florida Utility Coordinating Committee Meeting – 1 attendee (quarterly)	$1,400.00
Sales & service qualification course residential CNG units - 2 attendees	$4,000.00
Carbon cap & trade certification course - 2 attendees	$6,000.00
Total Training & Seminar	$102,140.00

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY AND EXHIBITS
Of
MARC L. SCHNEIDERMANN
On behalf of
FLORIDA PUBLIC UTILITIES COMPANY
DOCKET No. 080366-GU

Q. Please state your name and business address.

A. Marc L. Schneidermann, 401 South Dixie Highway, West Palm Beach, FL 33401.

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

A. I am employed by Florida Public Utilities as the Director of Corporate Services.

Q. When did your employment by Florida Public Utilities Company begin?

A. February 1989.

Q. Briefly describe your educational background and employment experience.

A. I earned a Bachelor of Science Degree in Mechanical Engineering from the Polytechnic Institute of New York in 1983. I received a Master Degree in Management with a concentration in Energy Management, from Polytechnic University during 1986. Since being employed by Florida Public Utilities Company (herein after referred to as "Company" or "FPU"), I have been responsible the Company's South Florida Engineering, Customer Service, Operations Departments as well as the Corporate Gas Logistics and Fleet Management Departments. Currently, as Director of Corporate Services I am responsible for the Company's Energy Logistics Department, the Fleet Management Department and the Safety Department as well as many special high level projects. Prior to joining Florida Public Utilities Company I was employed in excess of five years by the Brooklyn Union Gas Company ("BUG", currently known as Keyspan / National Grid). During my tenure at BUG I was assigned to the Systems Control section of the Gas Operations Department, the Synthetic Natural Gas and Liquefied Natural Gas Plant Engineering Department, the Regulatory Affairs and Supply Planning Department and ultimately the Gas Purchasing Department in various engineering, management, regulatory, gas planning and procurement positions.

Q. Have you previously testified before this Commission?

A. Yes, I provided expert testimony annually in the Purchase Gas Cost Recovery dockets from 1994 (Docket Number 940003-GU) through 2006 (Docket Number 060003-GU). I also provided expert testimony, over the last two decades, in the Company's last three filing for rate relief for the Company's Consolidated Gas Division in Docket Numbers 900151-GU, 940620-GU and 040216-GU.

Q. What are the subject matters of your testimony in this proceeding?

A. My testimony primarily relates to five specific matters.

(i) I will describe the methodology employed to develop the projections of customers and therm sales for the projected year as well as the development of FPU's proposed rates using the MFR Cost of Service model.

(ii) I am the Senior Manager responsible for the Company's gas purchases and I will describe how we developed our projected purchased gas cost.

(iii) I will address the Company's environmental expense projections related to the Company's involvement in former manufactured gas plants.

(iv) I am the project manager for the development of a new Operations Center and I will discuss the status of the project and our anticipated timeline.

(v) I am the Senior Manager responsible for the Company's Occupational Health and Safety. As such I will describe the safety enhancements we are projecting to make and discuss the projected increased cost due to the potential expectations for the changes to 49 CFR 192 related to integrity management proposed rulemaking.

Q. Which MFR Schedules are you sponsoring?

A. I am the witness for the following MFR Schedules:

E-1: Page 1: This schedule summarizes therm sales and revenue computed using present rates and 2007 units.

E-1: Page 2: This schedule summarizes therm sales and revenue computed using present rates and projected 2009 units.

E-1: Page 3: This schedule summarizes therm sales and revenue computed using proposed rates and projected 2009 units.

E-2: Pages 1 and 2: This schedule is a comparative schedule which summarizes data shown within the E-1 schedules.

E-4: Page 1: This schedule demonstrates monthly sales for the historical period of January 2005 through December 2007 and for the projected 2009 test year. It also shows the historical sales that occurred, by rate schedule, coincident with each historical peak month as well as for the projected March 2009 peak month.

E-5: All pages: These schedules illustrate monthly bill comparisons under present and proposed rates by rate class.

E-9: All pages: This section of the filing contains the relevant tariff sheets in legislative and final format showing the current language and rates, the proposed language and rates in legislative format to illustrate the interim proposed tariff and the final proposed tariff.

The H Schedules are used to model the Company's rate structure to determine the appropriate cost for providing service to each of the rate schedule based. This is done by applying historic and projected sales, revenue and expense data through various allocation methodologies to best determine what a suitable rate structure would be that allows for the Company to continue providing high levels of service, covers the Companies prudently incurred expenses and provides for a reasonable return on the Company's investments.

Q. Were customer count and sales projections performed under your direction?

A. Yes.

Q. In general, how were the projections of customers developed for the 2009 Projected Test Year?

A. First detailed analyses were made of the historical annual data of customers and sales by rate schedule for each of the Company's gas divisions for the period starting December 2004 through the end of July 2008. Customer growth was projected separately for South Florida division and the Central Florida division by rate: RS (Residential Service), GS and GSTS (General Service and General Service Transportation Service); LVS and LVTS (Large Volume Service and Large Volume Transportation Services). The IS (Interruptible Service) and ITS

(Interruptible Transportation Service) customer projections given the fact that the Interruptible rates have been closed to new customers as of June 30, 1998. We are proposing to continue offering an additional rate for Gas Lighting Service (GLS) due to the lower cost of providing service and the extreme market sensitivity. Furthermore, to reduce the financial impact to our smaller commercial customers, we are proposing to offer two configurations of the present General Services (sales and transportation) rate schedules which are shown as GS-1 GSTS-1, GS-2 and GSTS-2 and are both developed within FPU's Cost of Service filed herewith. The non-fuel energy charge is the same for all four General Service rate schedules. The monthly Customer Charge for the GS-1 / GSTS-1 is lower than the monthly Customer Charge developed for GS-2 / GSTS-2 customers. The newly proposed GS-1 and GSTS-1 rates schedules should help the Company retain and gain smaller commercial accounts which benefits all customers by having greater sales over which fixed costs are spread. The existing General Service historical data was used to develop this new rate split. In development of the rates consideration was given to the previously approved Residential Generator Service rate as well as the newly proposed General Service Generator rate. The rate making process for these services is described later in my testimony.

Q. In general, please describe the methods used to forecast the sales and number of customers by rate.

A. This was a six (6) step process outlined below:

Step 1: Estimate the historical relationship between Use per Customer (UPC) and Heating Degree Days (HDD), Price, and time (t)

In this step, we estimate how use per customer has varied with weather conditions, natural gas prices, and how it has changed over time. Separate models are estimated for each region and tariff group (combining the transportation and non-transportation tariffs). Monthly data from December 2004 through July 2008 was used to estimate the following equation:

$\ln(UPC^c{}_t) = a^c + b^c{}_{HDD} \text{ x } HDD_t + b^c{}_{Trend} \text{ x } Trend_t + b^c{}_{Price} \text{ x } Price_t + \Sigma_m\, b^c{}_m \text{ x } Month_t + e_t$

In this equation, $UPC^c{}_t$ is use per customer for customer class c in month t; a^c and the b^cs are the estimated coefficients; HDD_t is monthly heating degree days; $Trend_t$ is a time trend variable; $Price_t$ is the real purchased gas adjustment charge; $Month_m$ is a series of monthly indicator variables; and e_t is the error term. The error term is assumed to be serially correlated (a common feature of time series data), causing us to estimate the parameters using the Prais-Winsten method. The coefficient on the price variable was only statistically significant in two of the models (the West Palm Beach GS/GSTS and IS/ISTS groups), and was therefore only retained for those models. Please note, December 2004 is the first full month following the previous rate case, which included some changes in customer classes that complicate extending the analysis further back in time. Daily heating degree days are calculated as:

MAX[(MaxT + MinT) / 2 – 65, 0]

where MAX is the maximum function, MaxT is the daily maximum temperature, and MinT is the daily minimum temperature. The degree days are then added from the 16th of the previous month through the 15th of the current month to approximate the billing month degree days. Daily weather data were obtained from the National Climatic Data Center. Station #89525 is used for West Palm Beach and station #82229 is used for the Central region. Nominal gas prices are converted to real values using the Personal Consumption Expenditures Implicit Price Deflator from the Bureau of Economic Analysis.

Step 2: Adjust 2007 historical UPC to normal weather conditions

As a first step in creating the 2008 forecast of use per customer, the 2007 value is adjusted to account for the difference between actual and normal weather conditions in 2007. This adjustment is made using the $b^c{}_{HDD}$ parameter estimated in step 1, the historical HDD value, and normal HDDs (measured as the 10-year average), as follows:

$$UPC^{Normal} = \mathrm{EXP}\{\ln(UPC^{Actual}) + b^c{}_{HDD} / 12 \text{ x } (HDD^{Normal} - HDD^{Actual}\}$$

In this equation, EXP is the exponentiation function, and the estimated HDD coefficient is divided by 12 to account for the fact that the coefficient was estimated using monthly data, but it is applied to annual data in this adjustment.

Step 3: Forecast 2008 UPC

The 2008 forecast of UPC is equal to the weather-normalized 2007 UPC adjusted for the observed rate of change in UPC between 2007 and 2008. At the time the analysis was conducted, data were available through July 2008. Therefore, we measured the 2007 to 2008 rate of change by comparing the total UPC from January through July 2007 to the total UPC from January through July 2008. We assumed that this rate of change would persist for the remainder of the year.

Step 4: Forecast 2009 UPC

For all but two classes, the 2009 forecast of UPC is equal to the 2008 forecast UPC adjusted for the estimated trend in UPC estimated in Step 1. Specifically,

$$UPC^{2009} = \mathrm{EXP}\{\ln(UPC^{2008}) + b^{c}_{Trend}\}$$

For the West Palm Beach GS/GSTS and IS/ISTS groups, a price adjustment is also included in the forecast. The real gas price forecast for 2009 is compared to real gas prices for 2008 (forecast to the end of the year), and implemented into the 2009 forecast as follows:

$$UPC^{2009} = \mathrm{EXP}\{\ln(UPC^{2008}) + b^{c}_{Trend} + b^{c}_{Price} \times \ln(Price^{2009} / Price^{2008})\}$$

Step 5: Forecast 2008 and 2009 Numbers of Customers

The forecast of the number of customers by rate class for 2008 and 2009 is set at the average of the observed values for 2008 (through July). While most customer classes have experienced an increase in the number of customers since the previous rate case, the rate of increase has declined in recent years. Given the recent troubles in the housing market and in the general economy, it is perhaps a conservative estimate to assume that the number of customers will not decrease between 2008 and 2009, as we have done here. However, it is difficult to explicitly forecast the numbers of customers for two reasons. First, our analysis timeframe (December 2004 through July 2008) is relatively short. Given that economic and demographic data are often reported with an annual frequency, there is not very much information to use to estimate the drivers of changes in the number of customers. Second, the changes in economic conditions that occurred very recently are not included in the sample timeframe, preventing any explicit estimation of the effect of these events on customer behavior.

Step 6: Forecast 2008 and 2009 Revenues at Current Rates

Revenues for 2008 and 2009 are forecast using current tariff rates, the forecast therms, and the forecast number of customers. This method for 2007 allowed us to replicate the general ledger data to an accuracy level of 99.8% which are caused by variations which include, but are not limited to prorating the billing of customer charges to customers who commence or terminate service outside of the confines of the beginning or end of their normal billing cycles.

Q. Were the projections reviewed for reasonability by any other parties?

A. Yes. In fact, after the projections were completed they were also reviewed by the South Florida and Central Florida General Managers as well as the Company's Director of Marketing and Sales.

Q. Do you have anything further to add with respect to the 2008 and 2009 projections?

A. Only to state that I believe these estimates have been developed through detailed analyses of historical data and have been validated by independent reviews. The projected customers and sales can reasonably be expected to occur providing the Company has rates and rate structures that do not impede growth or cause a loss of customers. In the event of a continued economic decline through 2009 it may be possible that our customer and unit sales projections could be understated. Furthermore, based on the volatility of the world energy markets and recent history of strong storm and hurricane activities it may be possible that our projection of the costs of natural gas may be understated. We've made the best possible forecasts based on the non-typical situations occurring internationally or on the U.S. homeland. Extreme unusual factors did not effect our projections.

Q. How are these projections used?

A. The projections are used as a substantial factor in developing the Cost of Service model. The data used as the foundation for the Cost of Service model are contained within supporting Schedules E-1 through E-8.

Q. Please describe the Cost of Service Model.

A. The Cost of Service Model used was provided by the PSC Staff and is required to be submitted as part of the Minimum Filing Requirements (MFR). A Cost of Service model is an appropriate means of assigning costs to the various rate classes in a manner to reflect each class's causation of costs. Such studies require data input from accounting, engineering and our customer information billing system to develop how costs may be allocated. The Cost of Service model is needed in order to determine the revenue requirement of each rate class and to serve as a guideline for setting price levels for each rate class.

Q. Is it your intention to describe all the details of the Cost of Service model?

A. No. Since we have adopted Staff's model it should not be necessary to discuss all of the details. A few modifications were made and are discussed later in my testimony.

Q. Please describe the derivation of rates using the Cost of Service model.

A. The Cost of Service model actually starts with the population of Scheduled H-3. Within H-3 all projected expenses (operating, maintenance, depreciation, amortization, income taxes and taxes other than income taxes), rate base and accumulated depreciation) are listed by FERC general ledger and plant account classifier. Each one of these elements are reviewed to determine what methodology should be employed to allocate the costs and balances based on Customer, Capacity, Commodity or a combination of such. For example, customer service expense was allocated based on customer count, the Company's investment in distribution mains were allocated based on capacity and the gas supply expense was allocated based on volume, typically called send-out or sales. In this Staff provided model the nomenclature is "Commodity". This is traditionally the first step in a Cost of Service model.

Q. Now that you have data summarized by Customer, Capacity and Commodity classifiers what is done next to further the study?

A. Next, we prepare the H-2 Schedules. These Schedules are used to further allocate the data allocated by classifier in H-3 such that these data are then allocated to each rate based on allocation methodologies using peak and average sales data (in part from Schedule E-4), weighted number or customers, annual sales and certain direct assignments. The results of this step provide us with the theoretical total revenue requirement by rate.

Q. How are these data used to determine the individual rates?

A. The revenue requirement computed by rate, based on the results or Schedules H-3 and H-2 compared individually to the revenue that the Company would derive without making any rate change. The difference between the computed revenue requirement and the revenue that would be derived without making any rate changes equals the Company's Net Operating Income deficiency. This is shown within Schedule H-1 / Schedule D. The next step is to review the revenue that would be derived from each rate, the costs causation by rate and the rate based allocated to serve each rate class. The Rate of Return is determined by subtracting the revenue derived from each rate class from the expenses attributable to each rate class and then dividing the result by the rate base attributed to each rate class. Schedule H-1 / Schedule C shows (a) the results for the projected test year using the proposed rates and forecasted sales by rate class with each rate class providing for an equal rate of return which is commonly referred to as Parity; (b) the results for the projected test year using the proposed rates and forecasted sales by rate class with each rate class including a base rate adjustment shifting a portion of the revenue deficiency from the LV rates to the RS rates which will be describe in more detail later in my testimony; and (c) the rate of return that is projected to otherwise be realized, by rate class, absent a rate increase. Next H-1 / Schedule A is produced. This schedule shows the

Company's proposed "target revenues", by rate class, which would allow the Company to recover its expenses and provide for a fair return on its investments. The "target revenues" are reduced by the Company's projections of taxes and other operating revenue which is derived by performing services for which the Company has authorization to collect via the Natural Gas Tariff. This reduction in "target revenue" is based on the revenue expected to be derived by providing such services under the proposed rates shown within the E-3 Schedules. The "target revenue" is further reduced by the annual revenue the Company projects to derive from the product of the forecasted number of customer by rate class and the proposed applicable Customer Charges. The remaining unsatisfied revenue requirement by rate class is then divided by the projection of billing units by rate to determine the unitized proposed non-fuel energy charges. Schedule H-1 / Schedule A shows a comparison between the proposed and present tariff rates.

Q. Do you apply the results from the Cost of Service Model without adjustment?

A. Our goal is to ensure that our proposed rates do not cause degradation of customers within any of our rate classes and to be as close as possible to theoretical parity. We believe that the Customer Charges we proposed are fair and within what is generally charged in the marketplace. Generally, we set our Customer Charges much lower than what was determined by the Cost of Service model. For example, had we strictly used the results of the Cost of Service model, we would have had to propose a monthly Customer Charge or $17.30 for each of our customers served under our Residential Service rate. Instead, we are proposing a $12.00 per month customer charge for our residential customers. These types of market based adjustments are made for the purpose of retaining customers and growing our business. Had we used the $17.30 per month customer charge we could expect degradation of the lower to mid-range residential customer count and usage. Ignoring the market, these sorts of degradations could force a regulated utility to be in need of future rate increases sooner than otherwise expected thus having the effect of making service to some uneconomical and increasing the cost of serving the balance of a utility's remaining customers. Beyond being sensitive to the needs of our smaller use customers, we were very cognizant of the needs of our larger customers who can be swayed to using fuels other than natural gas due to the competitive nature of the energy business. To satisfy this need we used a direct allocation of revenue requirement from LVS & LVTS to RS. Absent this a revenue requirement shift which totaled $600,000 from the LVS and LVTS class we would expect to lose Large Volume customers which not unlike the above explanation of the effect of losing residential customers if we were to not meet the needs of the marketplace. Another driving force of employing this shift was to ensure that our average use customers in each rate class do not experience an overall increase, including the cost of gas, over 10%.

Q. Are there any newly proposed rates?

A. Yes. We have proposed to split the current General Service rate class into 2 rates. This is also due to meet the market sensitivity of the smaller existing and potential commercial customers. These rates will have the same non-fuel energy charges. The Customer Charge will differ based on the ratio of the GS-2 (and GSTS-2) to the GS-1 (and GSTS-1) the average cost of meter set and service by rate class shown in Schedule E-7. We propose GS-1 (and GSTS-1) and GS-2 (GSTS-2) rates take the place of the current GS and GSTS rates. The GS-1 and GS-2 rate provide for transportations service under the twin rate schedules GSTS-1 and GSTS-2. The incremental costs for providing the transportation services did not change and the GSTS-1 and GSTS-2 rate classes would experience the same incremental transportation expense had we kept the rates combined as GS and GSTS. Based on the relative GS-2 cost "Index" versus the GS-1 cost "Index" shown on Schedule E-7, the main differentiations between the new GS-1 (and GSTS-1) and the new GS-2 (and GSTS-2) rates are (a) the Customer Charge for the GS-1 (and GSTS-1) rate is proposed to be $20.00 per meter per month and the Customer Charge for the GS-2 (and GSTS-2) rate is proposed to be $33.00 per meter per month and (b) to qualify for the lower GS-1 or GSTS-1 Customer Charge, the customer must be a smaller commercial customer who twelve consecutive month consumption of natural gas is 600 therms or less for moving twelve month periods. In the event their usage grows, their account will be migrated to the GS-2 or GSTS-2 rate or the LVS or LVTS rate, which ever is applicable based on usage requirements.

Q. Are there any new or revised generator only service rates?

A. Yes. The Company is proposing to revise the Residential Generator (only) Service rate and to establish a Commercial Generator (only) Service (CS-GS) rate. The RS-GS rate was established under Docket Number 080072-GU and approved by Order Number PSC-08-0643-TRF-GU. The Company established this rate to meet the needs of the market and to increase their offerings to be similar to other natural gas utilities in Florida. The CS-GS rate, as like our other non-residential rates is offered as a transportation service also. Both rates will be administered in a method consistent with the above stated Commission Order. The residential generator rate will have a monthly Customer Charge equal to the RS Customer Charge. The commercial generator rate will have a monthly Customer Charge equal to the GS-1 Customer Charge. To ensure a fair recovery in the Company's investment in facilities that will help support the peak needs potentially created by generator load, the Company is filing for revising the RS-GS rate to be based on the monthly average residential consumption of 19.8 therms per month, based on our most recent studies. This is a reduction from the previously determined 22.17 average therms used per residential customer per month. Similarly the GS-GS rate is based on a minimum monthly usage of 39.52 therms per month which is the equivalent of the typical usage of a commercial generator rated at 1,900 cubic feet per hour being exercised for 15 minutes weekly. The residential and commercial generator only service account customers will not be billed for the physical natural gas commodity unless such passes through the meter-set serving their respective account(s).

Q. Please describe the development of the projected purchased gas cost for 2009.

A. The projection for FPU's cost of natural gas is composed of two essential elements; the forecast of the pipeline charges and the forecast of commodity costs of natural gas to be purchased by the Company. FPU has employed the identical forecasting methods since the mid-1990s and has an ongoing history of having the lowest purchased gas cost compared to all other LDCs regulated by the Florida PSC. We have employed the same techniques when we developed the projections for this rate proceeding during the summer of 2008. Furthermore, we have found this forecasting method to be extremely reliable and we have only had the need to request from the Florida PSC three (3) mid-course corrections during the last fifteen (15) years, during September 2000, January 2001 and September 2005, to reflect an expected recovery of purchased gas costs outside of the overall annual +/-10% PSC criteria. The mid-course corrections were all generally caused by changes in market conditions which could have never been foreseen.

Q. What is the projection period for this filing?

A. The projection period is January 2009 through December 2009.

Q. Please describe how the forecasts of pipeline charges and commodity costs of gas were developed for the projection period.

A. The purchases for the gas cost projection model were based on projected sales to bundled and unbundled customers. Florida Gas Transmission Company's (FGT) Demand, commodity effective charges (including surcharges) and fuel rates, at the time the projections were made, were used for the entire projection period.

The expected cost of natural gas purchased by FPU and delivered to FGT, for transportation to the Company and for FGT's fuel use factor, during the projection period was developed using the maximum New York Mercantile Exchange (NYMEX) natural gas futures settlement prices for the period of June 1992 through August 2008. We have also included the projected charges by Florida City Gas and Indiantown Gas Company for transporting relatively small amount of gas to FPU in the western portion of Palm Beach County and in Indiantown, respectively. The forecasts of the commodity cost of gas also takes into account the average basis differential between the NYMEX projections and historic cash markets as well as premiums and discounts, by zone, for term gas supplies.

Q. Please describe how the forecasts of the weighted average costs of gas were developed for the projection period.

A. FPU's sales to traditional non-transportation firm and interruptible customers were allocated all of the monthly pipeline demand costs, less the cost of capacity temporarily relinquished to pool managers for the accounts of unbundled customers, and were allocated all of the relevant projected pipeline and supplier commodity costs. The sum of these costs were divided by the projected sales level to said customers resulting in the projected weighted average cost of gas for traditional non-transportation firm customers and interruptible customers and ultimately the Purchased Gas Cost Recovery Factor (PGCRF a/k/a the Purchased Gas Adjustment cap or the "PGA cap") shown on Schedule E-1. Capacity shortfalls, if any, would be satisfied with the most economic dispatch combination of acquired capacity relinquished by another FGT shipper and/or gas and capacity repackaged and delivered by another FGT capacity holder. Obviously, if other services become available and it is more economic to dispatch supplies under those services, the Company will utilize those services as part of its portfolio. The PGA cap is the projected weighted average cost of natural gas, which is passed-on directly to FPU's customers, based on calendar year 2009. Throughout each year, we experience natural gas costs, delivered to FPU's City Gate Station, to be lower, at, and above the PGA cap. We manage the PGA charged by FPU to our customers in a similar format that escrow accounts are managed for the main purpose of providing our customers with some added price stability. The fuel markets have been very volatile within recent history. FPU's purchased gas projections were computed early in our rate case development and reflected projected costs at that time. The actual cost of gas may be higher or lower. The PGA cap is filed with the Commission who may approve or reject such cap.

Q. **Please update us on the Company's environmental expenses associated with the former Manufactured Gas Plants (MGP).**

A. We use or have used several properties with contamination that have pending or threatened environmental litigation. We are in the process of investigating and assessing this litigation. We intend to vigorously defend our rights in this litigation. We have insurance and rate relief to cover losses or expenses incurred as a result of this litigation. We believe all future contamination assessment and remedial costs, legal fees and other related expenses would not exceed the combined sum of any insurance proceeds received and any rate relief granted.

Q. What is the status of the former West Palm Beach MGP site?

A. The Company is currently evaluating remedial options to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by it in West Palm Beach, Florida upon which the Company previously operated a gasification plant. The Company entered into a Consent Order with the FDEP effective April 8, 1991, that requires the Company to delineate the extent of soil and groundwater impacts associated with the prior operation of the gasification plant and to remediate such soil and groundwater impacts, if necessary. The Company completed field investigations for the contamination assessment task in October 2006. Thereafter, the Company retained an engineering consultant, the RETEC Group, Inc. (RETEC), to perform a feasibility study to evaluate appropriate remedies for the site to respond to the reported soil and groundwater impacts. On November 30, 2006, RETEC transmitted a feasibility study to the Company and FDEP. The feasibility study evaluated a wide range of remedial alternatives. The total costs for the remedies evaluated in the feasibility study ranged from a low of $2.8 million to a high of $54.6 million. Based on the likely acceptability of proven remedial technologies described in the feasibility study and implemented at similar sites, consulting/remediation costs are projected to range from $4.6 million to $17.9 million. This range of costs covers such remedies as in situ solidification for the deeper impacts, excavation of surficial soils, installation of a barrier wall with a permeable biotreatment zone, or some combination of these remedies. By letter dated May 7, 2007, FDEP provided its comments to the feasibility study, the substance of which was discussed at a meeting between the Company and FDEP on September 14, 2007. A response to the comments was submitted by the Company to FDEP on October 31, 2007. We are awaiting FDEP's comments to the response. Based on the information provided in the feasibility study, the remaining legal fees are currently projected to be approximately $295,000. Consulting and remediation costs are projected to range from $4.6 million to $17.9 million. Thus, the Company's total probable legal and cleanup costs for the West Palm Beach site are currently projected to range from $4.9 million to $18.2 million. Presently, we believe final cost to be closer to $14 million and is equivalent to the estimate used in our last natural gas rate proceeding.

Q. What is the status of the form Sanford MGP site?

A. The Company owns a parcel of property located in Sanford, Florida, upon which a gasification plant was operated prior to the Company's acquisition of the property. Following discovery of soil and groundwater impacts on the property, the Company has participated with four former owners and operators of the gasification plant in the funding of numerous investigations of the extent of the impacts and the identification of an appropriate remedy. On or about March 25, 1998, the Company executed an Administrative Order on Consent (AOC) with the four former owners and operators (collectively, the Group) and the EPA. This

AOC obligated the Group to implement a Remedial Investigation/Feasibility Study (RI/FS) and to pay EPA's past and future oversight costs. The Group also entered into a Participation Agreement and an Escrow Agreement on or about April 13, 1998 (WFS Participation Agreement). Work under the RI/FS AOC and RI/FS Participation Agreement is now complete and the Company has no further obligations under either agreement. In late September 2006, EPA sent a Special Notice Letter to the Company, notifying it, and the other responsible parties at the site (Florida Power Corporation, Florida Power & Light Company, Atlanta Gas Light Company, and the City of Sanford, Florida, collectively with FPUC, "the Sanford Group"), of EPA's selection of a final remedy for OU1 (soils), OU2 (groundwater), and OU3 (sediments) for the site. The total estimated remediation costs for the Sanford gasification plant site are now projected to be $12.9 million. The Sanford Group was further advised that EPA was willing to negotiate a consent decree with the Sanford Group to provide for the implementation of the final remedy approved by EPA for the site. In January 2007, the Company and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by EPA for the site. The Company's share of remediation costs under the Third Participation Agreement is set at a maximum of $650,000, providing the total cost of the final remedy does not exceed $13 million. At present, it is not anticipated that the total cost will exceed $13 million. If it does, the Sanford Group members have agreed to negotiate in good faith at such time that it appears that the total cost will exceed

$13 million for the allocation of the additional cost. The Company has advised the other members of the Sanford Group that the Company is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by the Company in the Third Participation Agreement. On June 26, 2007, the Sanford Group transmitted to EPA a Consent Decree signed by all Group Members, providing for the implementation by the Sanford Group of the remedy selected by EPA for the site. The consent decree is currently being circulated within EPA and the United States Department of Justice for execution by those parties. Thereafter, the consent decree will be lodged with the federal court in Orlando, Florida. Following a public comment period, it is anticipated that the federal court will enter the consent decree. The Sanford Group will then be obligated to implement the remedy approved by EPA for the site. Remaining legal fees/costs are currently projected to be approximately $77,000. The Company's obligation under the Third Participation Agreement is $650,000. Thus, the Company's total probable legal and cleanup costs for the Sanford site are projected to be approximately $727,000.

Q. **What is the status of the former Pensacola MGP site?**

A. We are the prior owner/operator of the former Pensacola gasification plant, located in Pensacola, Florida. Following notification on October 5, 1990 that FDEP had determined that we were one of several responsible parties for any environmental impacts associated with the former gasification plant site, we entered into cost sharing agreements with three other parties providing for the funding of certain contamination assessment activities at the site. Consulting and remediation costs are projected to be $26,000 and legal fees are projected to be $4,000, for total probable costs for the Pensacola site of $30,000.

Q. What is the status of the former Key West MGP site?

A. From 1927-1938, we owned and operated a gasification plant in Key West, Florida. The plant discontinued operations in the late 1940s; the property on which the plant was located is currently used for a propane gas distribution business. In March 1993, a Preliminary Contamination Assessment Report (PCAR) was prepared by a consultant jointly retained by the current site owner and the Company and was delivered to FDEP. The PCAR reported that very limited soil and groundwater impacts were present at the site. By letter dated December 20, 1993, FDEP notified us that the site did not warrant further "CERCLA consideration and a Site Evaluation Accomplished disposition is recommended." FDEP then referred the matter to its Marathon office for consideration of whether additional work would be required by FDEP's district office under Florida law. Consulting and remediation costs are projected to be $83,000 and legal fees are projected to be $10,000, for total probable costs for the Key West site of $93,000.

Q. Is the Company proposing to modify the recovery period and total expected liability approved in its last natural gas rate case?

A. No. The current liability and amortization is valid and appropriate.

Q. Please describe the status of the future South Florida Operations Center.

A. The current South Florida Operations Center is located on the site of the former MGP plant. As such, we will have to relocate prior to commencing any cleaning-up of the existing site. The relocation would have to be permanent since due to the City of West Palm's Beach Comprehensive Land Use, the current site was re-zoned for usages which would not be consistent with our current use of the site. The current site is three (3) acres and is complimented by on-street parking. The Company purchased a 6.22 acres site located in the Town of Lake Park. Of the 6.22 acres a substantial portion of the site will not be developable due to the need for on-site storm water retention. The site does not have the benefit of on-street parking. As such, the 6.22 acre site is properly sized for our current operation conforming to the latest building and zoning regulations. We have been negotiating with three developers / builders to act as our agent to develop a site plan, to seek approval, to negotiate with the utilities and ultimately to bid the project to the trades and to manage the site development and construction. An Agreement between FPU and an Architectural/ Engineering (A/E) firm was negotiated during October 2008 through November 2008 and is expected to be fully executed during December 2008. The expected design fee is $186,500. The projected cost of site development and construction has been independently estimated at $4,744,000. FPU has worked diligently on determining the proper site for the new South Florida Operations Center. The inventory of industrial sites within the central eastern corridor of Palm Beach County has been very limited as many of the sites available were located in unincorporated Palm Beach County, which has a very long site plan approval and permitting timeline and / or have been located within sections of drainage districts which, under current regulations, require maintaining up to one-half of newly developed sites for storm water retention. We are confident that we purchased a site that could be developed with minimal interference as the site is located in the Town of Lake Park which is a small town and is very interested in FPU becoming a part of their town. By the late 2008 / early 2009 the final conceptual plan shall be completed and then we will proceed with getting the proposed site plan approved by the Town of Lake Park and other regulating entities. The entire process will result with the construction of the site being completed by November 2010. The Company is seeking the approval of including the cost of the property and related expense as well as the A/E cost and the full estimated construction cost for special future recovery. FPU's proposals are discussed within the pre-filed testimony prepared by Mr. Mesite. These costs will all be incurred as a direct result of the need for the Company to vacate the current Operations Center site due to the previously described clean-up of its West Palm Beach former Manufactured Gas Plant.

Q. Please describe the proposed increased expenditures in the Occupational Health and Safety areas.

A. The Company restructured a portion of its team during the winter of 2006. A major focus was placed on improving the Company's safety record. We have implemented many procedural improvements and improved on personal protective equipment issued to our crews. We have done all that we can reasonably accomplish without significantly increasing our safety budget. This rate case offers us the opportunity to further improve on our safety programs. Currently, the gas safety staff includes one manager and one gas coordinator as well as two safety positions in our electric operations. I am involved in gas safety for higher level issues and to provide guidance based on my substantial experience in gas operations. Along with many of my other responsibilities I only allocate an appropriate portion of my time to natural gas safety. The Safety Manager, the Safety Coordinator and my position are all housed out of the Company's West Palm Beach location. Furthermore, the Safety Department does not have any assigned support staff. I have also included in the budget funds for administrative support. I have also including funding for the following programs: a) Smith System Driver Training; b) WorkSTEPS program; c) driver's license monitoring; d) fees for a general liability Third Party Administration (TPA); e) additional training and recertification of the Safety Manager and Gas Safety Coordinator and e) the added cost anticipated to comply with the future Distribution Integrity Management rule. As we find an increase in the potential for litigation and higher than ever negligence awards, in order to position our Company as best as reasonable possible to avoid future catastrophic losses we will need to incur additional expenses for these programs. We currently do not have any similar programs in place.

The Smith System Driver Training program is provides hands-on, on-the-road training. Behind-the-wheel driver training is the foundation of the Smith System

Driver Improvement Institute. Smith System is the leader in professional driver training. Their trademarked Five Keys of Space Cushion Driving focuses on the core driving fundamentals of space, visibility and time. This real world training is supplemented through their extensive video and DVD library and web-based education. According to the Smith System, their results-oriented driver safety training and education has reduced collisions for fleets at over half of today's Fortune 500 companies. The expected annual cost to FPU's natural gas operations will be $31,000.

As with many companies we are beginning to realize the extra costs associated with having an ageing workforce. We have always provided physical examinations at the commencement of employment, however we need to assure additional protections for the Company to ensure on an ongoing basis that our employees are physically capable to do the work they have been assigned. We have identify a vendor named Worksteps which performs custom testing to determine an employee's ability to continue to perform his job tasks safely, identify cumulative trauma syndromes or disease processes which increase in incidence with aging and establish baseline data to qualify legitimate injuries and disqualify game players post-injury. For example, if an applicant is hired and through the course of his employment suffers any type of injury, the post-offer information is used to compare the employee's current status with his/her initial status. This alleviates speculation regarding pre-existing conditions and comparisons to other persons of his age and weight. Furthermore, since consistency of pre-injury and post-injury is easily monitored, the ability to detect a fraudulent report of an injury is greatly enhanced. WorkSTEPS has stated that their method has proven beneficial in reducing the dollar amount of court settlements to what is truly warranted as a deficit based on the injury that the individual suffered. The projected annual cost for FPU's natural gas operations to utilize the WorkSTEPS program is $30,600.

The Company's Human Resources department has been charge with periodically manually ordering and reviewing the Florida Drivers' License transcripts for each of its employee who operate motor vehicles for the Company. We have identified a service that will actively monitor convictions and notify us monthly of any new driving infractions. This will help the Company identify unsafe drivers on a much more expedited basis which could have an obvious impact on avoiding claims. The program we have selected is iiX which is a unit of ISO Claims Services, Inc. We are confident that this program will help us identify driver issues and help improve the safety of our fleet. The projected annual cost for FPU's natural gas operations to utilize the iiX service is $2,550.

Q. Please explain the situation with the Company Third Party Administration for liability claims.

A. The Company had a long term working relationship with a particular Third Party Administrator ("TPA"). Approximately one year ago said TPA was purchased by another firm which has been since renamed. Since the acquisition we were not satisfied with the services of the new firm. During the summer of 2008 we issued an RFP for a new TPA. We received three responses and selected the TPA that best fit our needs which also happened to be the lowest bidder. Due to the lack of performance by the former TPA there was not significant historical expense booked. The selected TPA will provide services to FPU which we are confident will help the Company to avoid the payment of frivolous claims as well as to reduce the likelihood of payment of extraordinary claims. This is also another tool in our portfolio of resources that we are proposing to avoid unusual non-recurring claims expense. The projected annual cost to the Company's natural gas operations is $12,750.

Q. **Please describe the additional projected expenditures for safety training and recertification of the Safety Manager and the Gas Safety Coordinator.**

A. The Company has adopted the use of the Bulli Ray Occupational Dog Bite Safety Training program for quite some time. There are projected incremental costs for training and refresher train-the-trainer program is estimated at 6,000 with $3,060 allocated to FPU's natural gas operations. Additionally, the Safety Department must attend additional training to improve its competency in certain perform certain safety training programs. The allocation to FPU's natural gas operations is estimated at $1,530.

Q. **Please describe the potential effect of the Office of Pipeline Safety's Notice of Proposed Rulemaking referred to as Distribution Integrity Management.**

A. The Notice of Proposed Rulemaking was issued in the Federal Register on June 25,2008. The proposed rule lists seven elements in an Integrity Management program which operators would have to develop and implement: 1) knowledge of infrastructure; 2) identification of threats; 3) evaluation and prioritization of risks; 4) mitigation of risks; 5) measurement and monitoring of performance; 6) periodic evaluation and improvement; and 7) reporting of results. Comments are being received on the NOPR however it is expected that compliance with the actual resulting rule will begin during 2009. We expect the initial effect of the final rule to have significant financial effects on the operations of gas distribution pipelines. The most recent estimated annual cost that we have seen is indicates a potential nationwide cost of $100 million for 1.9 million miles of gas distribution lines. This equates to approximately $53 per mile of main per year. Taking into account the appropriate ratios, the expected annual cost for FPU's gas operations to comply could be approximately $100,000. Since we cannot be sure exactly when the new rule(s) will take effect, we have figured the financial impacts as though we would start incurring costs during the summer of 2009. As such, we have included only $50,000 as projected expense associated with the additional compliance cost for the period covering July through December one-half of our initial annual projection, based on $53 per mile of main, of $100,000 We have included this estimated cost of compliance within our projections of 2009 expenses.

Q. Does this conclude you direct testimony in this Rate Proceeding?

A. Yes.

DIRECT TESTIMONY

DOREEN COX
ROBERT CAMFIELD

COST OF EQUITY AND RATE OF RETURN REQUIREMENTS
of
FLORIDA PUBLIC UTILITIES COMPANY

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

A. Witness Cox. My name is Doreen Cox. I am a Financial Analyst with Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Camfield. My name is Robert Camfield. I am a Vice President with Christensen Associates Energy Consulting LLC, and my business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. What is the scope of your testimony?

A. The scope of our testimony is twofold. First, we provide estimates of the cost of common equity to Florida Public Utilities Company ("FPU" or "Company"). Estimates of the equity cost rate underlie our common equity rate of return recommendation. Second, for the purpose of determining the overall rate of return and revenue requirements, we put forth the weighted-average cost of capital, stated on a regulatory basis including balances of customer deposits, deferred taxes, and investment tax credits. Our rate of return recommendation should be used by the Commission to set retail natural gas prices of Florida Public Utilities Company in the current docket.

Q. Please review your professional background and experience that qualifies you to provide such recommendations.

A. Witness Cox. I received a Bachelor of Science Degree in Management from the University of West Indies in 1979, with a concentration in Accounting. In 1990 I earned a Master of Science Degree in Accounting, also from the University of West Indies. I joined Florida Public Utilities Company in 1999, and I hold the position of Financial Analyst, which reports to the Chief Financial Officer ("CFO"). In this position, I support the CFO, the Accounting and Finance Division of Florida Public Utilities. In my current position, I cover a variety of operating and planning responsibilities including project assessment, budget and financial projections, and cash flow analysis. These responsibilities also include the preparation of quarterly reports to our Board of Directors, and the monitoring of compliance with respect to the Financial Covenants of Florida Public Utilities Company's long- and short-term sources of external funds. I was a witness in the Natural Gas and Electric rate relief proceedings before the FPSC: Docket Numbers 040216-GU and 070304-EI filed in May 2004 and August 2007, respectively.

Witness Camfield: The scope of my professional work includes capital valuation, economic cost assessment, regulatory economics and governance, and wholesale contracts and negotiation. For over 30 years I have been involved in numerous technical and policy issues facing regulated industries. I have testified on the cost of capital and provided rate of return recommendations on behalf of regulatory agencies, consumer advocates, utility associations, and gas and electric utilities. In both formal evidentiary regulatory proceedings and informal settings, I have made appearances on behalf of consumer advocacy groups, transmission and distribution companies, RTOs, integrated electric utilities, generation companies, regulatory agencies, and utility associations. I have provided evidence, analysis, and testimony on a variety of topics including power supply contracts, transmission congestion, marginal costs and cost allocation, tariff design and rate phase-in plans, corporate performance and cost benchmarking, generation supply plans, and load and energy forecasts.

Major consulting assignments include the management of power procurement solicitation, and a large market restructuring project in Central Europe. I have initiated or been involved in several innovations including two-part tariffs for transmission services, web-based self-designing retail electric products, marginal cost-based cost-of-service methods, and principles for efficient pricing of distribution services. I have published chapters in technical books, reports, and articles in noted industry journals such as *The Electricity Journal, IEEE Transactions on Power Systems*, and the *Council On Large Electric Systems*. Currently, I serve as Program Director of the Edison Electric Institute's *Market Design and Transmission Pricing School*. I have held the position of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I hold a masters degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

SUMMARY OF RATE OF RETURN RECOMMENDATIONS

Q. Please summarize the proposed rate of return recommendations.

A. The recommend overall rate of return is 8.74%, and is based on the regulatory capital structure for 2009. The recommended rate of return on common equity is 11.75%, which is determined by applying several cost-of-capital methods to two samples of utilities of comparable risk.

The proposed rate of return incorporates: 13-month balances and accompanying cost rates of long- and short-term debt; preferred stock; common equity; and regulatory components including customer deposits, investment tax credits, and deferred taxes, as projected for 2009.

Because of the Company's exceptionally small size, the return on equity recommendation for Florida Public Utilities Company may be conservative. As demonstrated through empirical studies, the risk and the cost of capital increases as the size of market capitalization of firms declines.

The Company intends to issue new common equity shares during 2009, such that the projected year-end capital balances, for the regulatory capital structure, contain somewhat greater equity participation (46%) than the average (42%). Because the cost rate attending common equity is above the Company's overall rate of return, the projected four percentage point increase in equity participation results in a higher required rate of return of 8.94%, an increase of 20 basis points. The implied impact on the revenue requirement in 2009 as a result of using the year-end capital structure is approximately $240,000.

In view of the exceptional stresses facing financial markets currently, and the Company's comparatively small size, it is vital that the Company maintain satisfactory interest coverage. Containing debt to moderate levels, as obtained through the successful issuance of additional shares of common stock and maintaining modestly higher equity participation, contributes substantially to overall coverage. For this reason, we recommend that the Commission give serious consideration to the year-end capital structure for the purpose of setting retail prices in the current docket.

BACKGROUND: COST OF CAPITAL, NATURE OF CAPITAL MARKETS

The *Cost of Capital* is the underlying interest rate used by investors to discount the expected benefit flows of capital resources, including returns to financial assets, and is sometimes referred to as the rate of discount. The cost of capital is the compensation, measured as the percent of principal, required by investors for postponing consumption, for expected inflation, and for exposure of investment to risks of various dimensions. Generally speaking, the degree of risk is specific to various classes of investment vehicles.

The cost of capital is determined by the demand for capital, supply of savings, expectations of inflation, and perceptions of risks harbored by participants in capital markets. The demand for and supply of capital are determined by expectations of future levels of economic activity, while expected inflation is driven largely by monetary policy over the relevant timeframe. Perceptions of risk, in turn, cover many dimensions including: uncertain government policy; the effects of natural phenomena such as weather including violent storms, droughts, and floods; and, in some regions of the world, war and civil unrest. Currency risks enter the picture in the case of foreign investment. The cost of capital—essentially, the underlying discount rate of investors stated in nominal terms—increases with rising demand for capital, with expectations of higher rates of inflation, and with heightened perceptions of risk. Arguably, risk is the key contributing factor for the estimation of the cost of capital and is the central concern of contemporary debt and equity markets worldwide.

Financial assets include a multitude of debt vehicles, equity, and derivatives such as options on stocks; structured finance such as collateralized debt obligations; and credit insurance. Derivative instruments assume a steadily expanding range of products tailored to the preferences of participants of capital markets, where participants include households and small investors, small businesses, corporate organizations, and government entities. Participants across these segments—*i.e.*, investors including lenders and holders of common and preferred stock—can supply capital while other participants (such as borrowers and common stock issuing companies) demand capital.

Commercial banks, credits unions, finance companies, capital exchanges, and insurance companies serve as intermediaries that provide the institutional means that facilitate the interaction and linkage of the supply and demand sides of markets. These functions constitute the essential process of lending and borrowing through various debt vehicles, the issuance of equity vehicles, and mechanisms to hedge risks. Banks and credit unions borrow (and store) financial assets that in turn are invested in the form of debt and, to a lesser extent, equity. Household debt vehicles include, for example, personal loans covering appliances and household services; credit card mechanisms through finance companies and banks; and real estate loans. Business loans include short-term loans and lines of credit with banks, inventory financing through business wholesalers, and commercial paper of various terms and credit risk ratings. Corporate debt can be in the form of lines of credit with banks, and mortgage and debenture bonds, while government debt can be in the form of revenue bonds of cities, credit lines with banks, and short- and long-term debt of various terms. As mentioned, debt can also be in the form of structured finance. Since the early 1990s, structured financial vehicles have come to represent a progressively larger share of financial media.

Equity (or, *Common Equity*) refers to net accumulated value of the contributed capital from investors. Generally speaking, equity is in the form of common and preferred stock. Stated in accounting terms, equity includes the accrual of retained earnings where the investor, through the purchase of stock, assumes a share in the ownership of a corporate entity. The supply and demand forces inherent to equity markets will often value common equity at levels substantially below or above book value. In some cases, debt instruments can have some of the characteristics (and risks) of equity and will participate in equity returns and may also have rights of conversion to common stock.

Derivatives are financial instruments whose value is 'derived from' inherent value of the underlying assets. The valuation of a derivative depends on investor expectations regarding the underlying asset. Derivatives, the common forms of which include options and forward contracts, provide a basis for hedging of risk associated with the value of the asset, but can also be used for speculation on that value.

The cost of capital associated with financial assets is determined by investors; in the large these are individuals and entities (including government entities) that provide savings and thus the accumulation of capital. In the case of financial assets, expected benefits are in the form of future cash flows including interest payments, dividend payments, market appreciation, and return of principal. When investors supply funds to entities such as utilities and governments, they are postponing consumption—giving up the value obtained from alternative expenditures. They are also exposing funds to potential devaluation from ongoing inflation, as well as to various risks that attend (uncertain) future cash flows. Investors are willing to incur these risks only if they are adequately compensated. While the market prices of other inputs including labor, materials, and energy can be easily verified, the cost of capital—essentially, the price of capital—is not easily discerned and often is case-specific. All too often determining a price requires estimation through the cautious application of analytical methods. While the underlying discount rate can be masked by the demand for liquidity, the cost of capital remains positive in the absence of inflation and risks, as savers require compensation for foregoing the right to use the funds saved for consumption of goods and services—essentially, the time value of money.

In addition to the global risks alluded to above (weather, government policy, etc.), dimensions of risk also cover idiosyncratic factors associated with specific capital resources, such as those of individual entities or companies. Accordingly, financial markets will re-price downward the bonds of a private company, should the *current* financial condition of the company unexpectedly decline. Essentially, the decrease in the company's condition (reflected as reduced interest coverage) typically causes the expectation of the future condition of the company to decline as well. Expectations of future financial conditions of a specific company are idiosyncratic risks. Because the cost of capital rises with increased risk, the prices of the bonds decline. Discount rates, in the form of the net interest rates or bond yields (and yield to maturity) and bond prices move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

To facilitate the commitment of capital (investment) by savers and their agents to the firm, the firm offers property rights, including bonds and promissory notes to debt holders, and shares of stock to equity investors. These property rights define the commercial terms and conditions under which savers and their agents commit capital. Property rights are capital (financial) assets, and are generally tradable in organized financial markets or on an over-the-counter basis. Financial assets are claims on the income of the firm as compensation for the commitment of capital, and are the financial obligations of the firm. Shares of stock constitute ownership in the firm.

In the case of long-term debt—*i.e.,* mortgage bonds, debentures, and long-term notes—the interest on the principal (face) amount of a bond (debt) or the coupon rate on the share of preferred stock defines the level of compensation. Often, the interest rate is a predefined annual rate that remains fixed over the term of the debt. However, long-term debt instruments can have a number of other provisions that, in essence, provide for more complete contracting by managing risks through risk sharing between the debt holders and the borrower (the firm). These provisions can include: 1) adjustments to the rate of interest to reflect contemporary market conditions *and* rates of inflation, 2) participation in the earnings of the firm, 3) conversion rights, and 4) voting rights in the management of the firm.

In the case of short-term promissory notes, agreements with commercial banks define the mechanism by which interest is determined. Often, the commercial terms of promissory notes define interest to be paid monthly on the outstanding daily balance (principal outstanding). The rate of interest applied to the outstanding balance is typically tied (indexed) to the interest rate on obligations of some widely known financial market—say, the London Interbank Offer Rate (LIBOR) or the Federal Funds rate—which also varies daily or monthly.

Common stock property rights are somewhat different from other financial obligations because, as owners of the firm, the returns to shareholders are residual amounts following the payments to other resources employed by the firm, including debt obligations. Common equity is essentially compensated last, and bears the burden of much of the business, regulatory, and financial risks of the firm. For this reason, common equity in virtually all cases is more costly than other forms of financial instruments.

As with other durable good markets such as equipment, capital markets have primary and secondary dimensions. Primary markets are the institutions and processes that facilitate the initial sale of the financial obligations of the firm to initial investors. Secondary markets are structured market processes (*e.g.*, stock exchanges) that provide a means by which investors can purchase and sell existing rights, including shares of stock and debt obligations. Financial instruments can assume many forms, and debt securities (bonds) and equity shares are actively traded in financial markets, which are generally considered to be highly liquid and competitive. However, to the degree that financial obligations: 1) carry specialized and non-common commercial terms, and 2) secondary and primary markets are less liquid, holders of such obligations assume higher risks, other factors held constant. This is the case where the pool of buyers and sellers is limited and the volume of transactions is comparatively small. Relatively low levels of liquidity imply higher transaction costs and risks to investors, which translates directly into higher costs of capital to the firm.

Some markets can be characterized as 'competitive'; and markets are said to be competitive if certain conditions exist. Markets can be characterized as competitive if they involve: 1) large numbers of buyers and sellers, 2) readily available and complete information relevant to the determination of prices, and 3) low transactions costs. Because of the workably competitive nature of financial markets, arbitrage opportunities are more or less exhausted. This means that, for both primary and secondary markets, financial property rights trade at levels (prices) such that perceived risks and opportunities for prospective returns to capital are appropriately balanced and approximate those of other investment opportunities. Thus, over prospective periods, above-normal returns cannot be realized by investors in systematic fashion.

Under the assumption of market efficiency, the competition inherent in U.S. and worldwide financial markets implies that the prices of common shares and bonds are at levels that reflect the opportunity cost of capital. As an example, assume that the perceived risks attending the returns to common shareholders of Firm A are equivalent to those of Firm B and other firms. If the share prices of Firm A suggest a market return of 10%, while the prices of Firm B and other firms of comparable risks suggest (allow) market returns of 13%, the market price of Firm A will fall to a level that provides a basis for market returns of just 13%, prospectively. A price that allows for a 10% prospective market return is insufficient in the presence of opportunities for a market return of 13% on alternate investments of comparable risk. Essentially, the 13% market rate of return on investment alternatives constitutes the opportunity cost of capital. Most remarkable is the expedience—literally, within minutes for highly liquid financial markets—with which share prices adjust to levels that balance prospective returns to equilibrium levels *based upon perceptions of risks*. In short, equivalent and comparable risks translate directly into comparable rates of return, which is the cost of capital of common shareholders in and of the firm.

As mentioned early on, the cost of capital is a function of the demand for and supply of capital, investor expectations of inflation, and investor perceptions of risks. Because the conditions of demand and supply as well as expectations of inflation are more or less common to financial markets at any point in time, financial vehicles are differentiated by risks. Hence, the expected returns and prices of bonds and common shares (normalized for denomination and size) at any point in time are largely if not exclusively differentiated by perceptions of risk, and taxes on income.

In summary, whereas the cost of skilled labor, materials and supplies, and fuel used in the process of providing utility services are expressed in money terms, the cost of capital is expressed as an interest rate, typically shown as an annual percentage of investment. This means that the costs of the capital resources employed by FPU, including distribution mains, secondary distribution equipment, meters, safety equipment, maintenance buildings, trucks and other vehicles, computer systems, software, office facilities, inventory and stores, and land—essentially, the natural gas rate base of FPU—are reflected as annual carrying charges. The cost of capital for FPU—or perhaps more accurately, the *cost rate of capital*—is referred to as the *required rate of return* (%) on the capital resources committed by investors to the Company, where capital is valued at either original cost, which is the convention within the U.S., or fair value as is often the case in other regions of the world.

<u>**FAIR RATE OF RETURN, CAPITAL ATTRACTION**</u>

Q. Would you please review the statutory mandates that guide the determination of rate of return for public utilities?

A. Legal guidelines for rate of return utility regulation of the North American Continent have been discussed extensively, and are delineated by key decisions of the legal authorities in the U.S. and Canada. As a point of departure, the statutory principles of rate of return for public utilities rest substantially with two decisions of the Supreme Court of the United States. In the *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia* case (262 U.S. 679, 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

> ...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; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high

> or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

A second landmark decision of U.S. Supreme Court echoed and expanded upon the fair return standard established by the "Bluefield" decision cited above, for capital committed to public utilities. This second decision is the *Federal Power Commission v. Hope Natural Gas Company* case (320 U.S. 391, 1944); a relevant passage of this latter decision is as follows:

> 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 return 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.

These longstanding decisions provide the recognized framework for determining the fair rate of return on capital committed by investors to public service. In these decisions, in clear and readily understandable terms the U.S. Supreme Court codified a statutory benchmark that serves as the basis to set fair and equitable prices for retail public services such as natural gas, while also providing a fair rate of return on the capital provided by investors. Though they reach back many years, these decisions remain to this day the cornerstone for the determination of rate of return requirements. The challenge for governing authorities, utilities and service providers, and interested parties is to make these principles operational in contemporary regulatory processes.

Principles such as these support the practical experience and management of both small firms and large corporate entities. The cost of capital concept may also be interpreted from the perspective of internal investments and the demand for resources. Regulated utilities accommodate the ongoing and steadily rising demand for services, which involves expanding employment of resources, capital in particular. Senior managers of firms, as agents for the ownership or controlling interest of the entity such as shareholders or a local municipality, are responsible for ensuring that the expected internal returns on incremental capital committed by the firm are equivalent to the cost of capital to the firm—*i.e.*, investors' rate of return requirements. The adequacy of the internal returns on incremental investment by electric utilities to fund capital at full opportunity costs, however, is highly dependent upon the soundness of the regulatory governance structure which ensures that the utility has the opportunity to obtain sufficient revenues, which in turn provide adequate returns on new capital.

When the rate of return, as set by regulators, leads to inadequate returns to capital or to the expectation that returns to capital are likely to be insufficient, utility managers are understandably reluctant to make investments in infrastructure. Indeed, when the expansion of capital resources occurs under a regulatory requirement including the obligation to serve, the absence of adequate returns implicitly constitutes the confiscation of the capital. Under these regulatory conditions, the utility is forced to provide services that involve new investment even though adequate returns are not obtainable. The result is a failure of the utility to attract capital on fair terms and, as a result, the confiscation of capital of investors—an outcome that comes about from the inherent efficiency of competitive capital markets.

Investors, investment rating agencies, investment banks, and commercial bank lenders follow regulatory developments. Anticipating a shortfall of the internal returns to capital with respect to rate of return requirements, capital markets bid down the prices of the outstanding securities of the utility. The reduced market capitalization of the utility constitutes, arguably, the confiscation of the existing capital of holders of the utility's securities. Essentially, the utility has failed to (or simply cannot) attract capital on fair terms—terms that do not cause outstanding investors to incur wealth losses.

CAPITAL STRUCTURE, WEIGHTED-AVERAGE COST OF CAPITAL

Capital Structure refers to the means—*i.e.*, financial vehicles—by which private and public entities underwrite physical capital and other assets. Capital structure can involve several types of mechanisms including long- and short-term debt, preferred and preference stock, common equity, and capitalized leases. Under utility regulation, these traditional financing vehicles are often augmented by other sources of funds including customer deposits, deferred balances for income taxes, and investment tax credits.

The relevant policy issue is the level of financial leverage, measured as the ratio of debt to equity that comprises the capital structure stated on a traditional basis. Because debt is generally less costly than equity, it is appropriate for the firm to underwrite its assets with some degree of financial leverage. The appropriate amount of leverage is a matter of operating and business risk, dependent on the expected level and variability (measured by the well-known statistical metrics, the mean and the variance) of future operating income. In brief, highly stable flows of operating income (and internal cash), which can be interpreted as the total book returns to capital, provide a basis for the firm to employ higher levels of debt. Higher leverage, however, increases the variability of interest coverage and thus the cost of debt and the *cost of equity* as a result. Thus, the financial policy issue regarding debt leverage is a matter of determining the level of debt that minimizes the weighted-average cost of capital ("WACC"). At relatively low levels of debt, the WACC declines as leverage rises. Beyond a certain point, however, the expected variability of operating income of the firm relative to equity ownership value begins to rise, causing the WACC to increase. In short, the cost rates of debt and equity are sensitive to the fractions debt and equity participation within total capital. Thus, the relevant question is focused on defining the appropriate and acceptable level of leverage, given the inherent business and operating risks of the firm.

Decades back, it was common for gas and electric utilities to underwrite assets with upwards of 60-65% debt and corresponding levels of equity of 40-35%. Currently, however, both mid-sized and large gas and electric utility companies typically finance assets with participation shares of 48-58% debt, and 52-42%

equity. The gradual evolution favoring lower levels of debt financing is in response to changes in the utility services industry. Several recent changes in the business environment facing utilities have precipitated the reduction in debt financing by retail utility electric providers. Key institutional changes include market restructuring involving competitive entry for retail unbundled services; sharp increases in input prices; closer integration of retail services and wholesale energy markets generally, where energy commodities exhibit much higher levels of price variation and volatility; less restrictive regulatory governance structure including price cap regulation and earnings sharing mechanisms; and uncertain future requirements for reliability, safety, and environmental compliance.

As a general rule, the governing regulatory authority should adopt the observed or projected capital structure including regulatory (non-traditional) components, where such result is well aligned with least-cost principles. However, where the observed capital structure constitutes a clear departure from least cost—with unusually high concentrations of debt or equity participation—it may be appropriate for regulatory authorities to consider the adoption of a hypothetical or imputed capital structure, for use in the determination of retail prices. In addition, in the case of unusually small sized entities such as FPU, which are susceptible to unforeseen business events whose risks cannot be readily diversified or insured, it may be appropriate for regulatory authorities and the utility to employ a higher concentration of equity participation in total capital.

METHODOLOGY AND RESULTS:

RATE OF RETURN FOR FLORIDA PUBLIC UTIITIES COMPANY

Q. What is the appropriate capital structure for determining retail prices in this docket?

A. As summarized above, the Company's overall rate of return is based on a 13-month regulatory capital structure. This approach, as projected for 2009, follows the prescribed methodology of the Florida Public Service Commission. As we demonstrate, such approach understates the weighted-average cost of capital of the Company on a going-forward basis. Accordingly, we request that the Commission give consideration to the year-end capital structure, also for 2009.

The starting point, for 13-month average and year-end capital structure, is the Company's conventional capital structure. On a 13-month basis, the conventional capital structure includes: 1) long-term debt capitalized at 39.99% of total capital, with an accompanying cost rate of 7.90%; 2) short-term debt represents 11.39% at a cost rate of 4.71%; 3) preferred stock participation in total capital is 0.50%, with a cost rate of 4.75%; and 4) common equity representing 48.13% of the Company's total capital with an estimated cost of equity of 11.75%. The weighted-average cost of capital (WACC) for the conventional capital structure is 9.38%, and is shown below.

WACC, Conventional Capital Structure (2009 Average)

Capital Component	Share	Rate	Contribution
Long-Term Debt	39.99%	7.90%	3.16%
Short-Term Debt	11.39%	4.71%	0.54%
Preferred Stock	0.50%	4.75%	0.02%
Common Equity	48.13%	11.75%	5.66%
Aggregate	100%	9.38%	9.38%

In addition to the conventional components, the capital structure for determining the overall rate of return contains balances for customer deposits, accumulated deferred taxes, and accumulated investment tax credits of the Company dedicated to providing retail natural gas services. The regulatory capital structure includes the conventional components scaled *pro rata*, such that the regulatory capital structure, in total, matches the rate base attributable to the provision of natural gas services.

Stated on a regulatory basis, the 13-month average balances for the components are long-term debt of 35.07%; short-term debt, 9.99%, preferred stock, 0.43%, and common equity of 42.21%. To these balances are added customer deposits, deferred taxes, and accumulated investment tax credits with corresponding capitalization shares of 8.38%, 3.76%, and 0.16% respective. This results in a WACC of 8.74% stated on a regulatory basis, which is the overall rate of return level utilizing 13-month balances as prescribed by the Commission. Please reference Exhibit 1.

WACC, Regulatory Capital Structure (2009 Average)

Capital Component	Share	Rate	Contribution
Long-Term Debt	35.07%	7.90%	2.77%
Short-Term Debt	9.99%	4.71%	0.47%
Preferred Stock	0.43%	4.75%	0.02%
Common Equity	42.21%	11.75%	4.96%
Customer Deposits	8.38%	6.13%	0.51%
Deferred Taxes	3.76%	0.00%	0.00%
ITC at Zero Cost	0.00%	0.00%	0.00%
ITC at Overall Cost	0.16%	9.38%	0.01%
Aggregate	100%		8.74%

Holding the component cost rates unchanged, the year end 2009 weighted-average cost of capital is 9.63% stated on a conventional basis. Year end balances have equity participation rising by 4.62 percentage points to 52.75% because of the issuance of additional shares of common equity scheduled for 2009. Similarly, the year-end regulatory capital structure has somewhat higher equity participation of 46.03% with an accompanying WACC of 8.94%, an increase of 20 basis points. Please reference Exhibit 2 which presents the year-end capital structure and WACC, stated on a conventional and regulatory basis.

Q. **Would you please review your recommendation for the cost rate of long-term debt?**

A. Florida Public Utilities has issued bonds to raise external capital and to maintain a balanced capital structure. Our current outstanding long-term debt consists of five issues of first mortgage series bonds that were issued over the 1988-2001 period. These five issues have maturity dates ranging from 2018 to 2031, and carry coupon interest rates ranging from 4.90% to 10.03%. Annual sinking fund payments on the two issues maturing in 2018 began in May 2008.

The overall weighted-average cost rate for the Company's projected-long term debt for 2009 is 7.90%, as mentioned. This embedded cost rate is determined according to contemporary accounting conventions, and is in keeping with the regulatory approach adopted by the Florida Public Service Commission Staff. The methodology accounts for the 2009 amortization schedule of issuance costs. The average net outstanding balance of long-term debt for '09 also reflects unamortized issuance costs as well as the sinking fund schedules. The determination of the 7.90% long-term interest cost rate can be found in Exhibit 3.

The Company does not expect to issue additional long-term debt prior to 2010.

Q. Please review the cost rate of short-term debt and related issues.

A. Florida Public Utilities Company maintains, and expects to maintain over the foreseeable future, a short-term debt facility with Bank of America (BOA). The provisions of the short-term debt facility make available short-term debt at a cost rate determined according to the London Inter Bank Offer Rate (LIBOR). The loan agreement for short-term debt was amended in March 2008 to incorporate a revised expiration date of July 1, 2010 and to provide the option to expand the line of credit up to $26 million. Under the revised terms, the effective interest rate spread on outstanding daily balances was reduced by ten basis points—from 0.90% to 0.80%.

The expected effective short-term debt cost rate incurred by the Company for short-term debt, for use to determine prices in the current docket, is determined by first projecting the rate for the U.S. Federal Funds (or simply Fed Funds) for the timeframe over which the natural gas prices will apply. Given the historical relationship between LIBOR and the projected rate for U.S. Fed Funds, the projected LIBOR rate is determined by holding the historical interest rate spread between LIBOR and Fed Funds. Once determined, the short-term debt cost to Florida Public Utilities is obtained by incorporating the 80 basis points margin above LIBOR plus other charges covering the unused balances and the fee for the availability of the credit facility.

The key short-term interest rate is the Fed Funds rate. As we have alluded, LIBOR has traded at an average of 17 basis points above Fed Funds since January 2001. The Fed Funds interest rate is largely determined by the monetary policy of the Board of Governors of the Federal Reserve Bank, and is strongly influenced by interest rates on short-term U.S. Treasury Bills. Historically, Federal Funds "trade" at an interest rate slightly above that of 90-day T-Bills. The Fed Funds rate in this filing is projected to be 2.98%, which is the average rate from January 2001 through July 2008. This projected Fed Funds rate implies a 30-day LIBOR of 3.15% (2.98% + 0.17%). In turn, this result translates into a cost rate of 3.95% for the outstanding balances on short-term debt balances, once the margin above LIBOR (0.80%) is recognized. The fees associated with the unused credit line and direct charges, when coupled to charges for the outstanding balances, produce an overall effective short-term debt interest rate of 4.71%.

It is useful to describe briefly the longer history as it relates to the determination of short-term interest rates. Specifically, the Federal Reserve followed a policy of interest rate targeting for a number of years prior to late 1979, when money supply targeting was abruptly adopted. The result was high and volatile short-term interest rates, although money supply targeting arguably reduced substantially the high levels of inflation and inflation expectations of the early 1980s. From the mid-1980s forward, monetary policy has been more accommodative of economic conditions and needs, within the long-term objective of containing overall inflation at moderate levels. As observed during the 1990s, the Federal Reserve has employed an array of indicators and metrics to determine monetary policy, including reserve targeting. As a general rule, reserve targeting gives rise to greater variation in short-term interest rates, while interest rate targeting, which suggests greater variation in the supply of reserves, results in less variation. At this writing, short-term interest rates, with Fed Funds residing at 1.00%, are expected to hold steady over the near term in view of the current slowdown in economic activity, prior to returning to normal levels.

Finally, we wish to mention that, because the average daily balances are considerably above month-end balances, the effective cost rate for short-term debt for 2008 and 2009 is determined on a basis of average balances. Specifically, the cost rate draws upon and utilizes the ratio of the average daily balances to the month-end balances for each month during 2007, as a basis to determine the average daily balance for 2009. We believe that this approach provides a more accurate reflection of the Company's true balances of short-term debt, interest charges and, thus, short-term interest cost rate. However, the traditional and regulatory capital structures are determined according to month-end balances for the several items that comprise the capital structure, which is the conventional approach.

Please reference Exhibit 4, which presents the calculations used to determine the short-term debt cost rate for 2009.

Q. Please review the cost rate of preferred stock.

A. FPU's preferred stock consists of one issue of 6,000 shares that dates to December 28, 1945 and had a coupon rate of 4.75%. Please reference Exhibit 5.

Q. Would you please discuss your general to approach to determining the cost of equity and the common equity rate of return recommendation?

A. We determine the rate of return for common equity by applying four capital valuation methods, including Capital Asset Pricing Model, Discounted Cash Flow, Risk Premium, and an assessment of Realized Historical Returns. In particular, the Risk Premium methodology infers the underlying opportunity cost of capital on a basis of the relative risks of debt and equity capital. The fourth approach constitutes a benchmark by which investors gauge the future earnings prospects of financial assets and, along with other information, form expectations of future returns where, by assumption and empirical assessment, efficient markets value (price) financial assets accordingly. The four methods are applied to two samples of stocks of comparable risk listed on U.S. stock exchanges. The first ("Sample 1") consists of mid-sized natural gas distribution companies and the second ("Sample 2") comprises mid-sized electric utilities.

The four cost of capital methods are well founded in modern finance theory, and are often used for capital valuation. The result of the cost-of-equity studies obtains an overall cost estimate of 11.67%, as shown in Exhibit 6, which translates into a common equity rate of return recommendation of 11.75%.

Q. What is the appropriate cost of customer deposits held by FPU in the projected test year?

A. The cost rate of outstanding balances of customer deposits is estimated to be 6.13% for 2009. Customer deposits are specific to the Company's natural gas division, and to residential and non-residential groups. The relative shares of each group in the total balances of customer deposits, 89% and 11% respectively, is expected to remain fairly constant over the next few years.

The cost rates are determined by the Florida Public Service Commission and, currently, are set at 6.00% and 7.00%, respectively, for residential and non-residential customers. The result is an overall weighted-average cost rate of 6.13%, which is applied to the average 13-month outstanding deposits, as projected for 2009.

The determination of the 2009 cost rate for customer deposits appears in Exhibit 7.

Q. Would you please discuss the appropriate approach to determine the cost rates applicable to deferred taxes and investment tax credits?

A. Accumulated balances of deferred taxes and investment tax credits arise from the normalization procedures of accrual accounting. This approach capitalizes the tax benefit of, say, accelerated depreciation of capital, and then amortizes the balances to income in equal installments over the life of capital. The unamortized balances of deferred income taxes—and investment tax credits—are carried as deferred liabilities.

For purposes of determining regulated prices, it is common to subtract the balances of deferred tax liabilities from the rate base, or to include the liability in the capital structure at zero cost. The latter approach is the longstanding methodology adopted by the Florida Public Service Commission, and is the approach taken by the Company in the current filing before the Commission.

CAPITAL STRUCTURE AND INTEREST COVERAGE

Q. Are there specific issues for consideration by the Commission regarding the capital balances used to determine the capital structure?

A. There are two issues that we wish to bring to the attention of the Commission. They concern: 1) the year-end capital structure and 2) the exclusion of Flo-Gas from the Company's balances of common equity. These issues can be restated as questions. First, should an average or year-end capital structure be utilized? Second, should the Commission utilize a consolidated capital structure for setting retail natural gas prices, and under what conditions should the Commission depart from a consolidated capital structure?

Before launching into a discussion of these issues, we wish to identify an overarching objective for regulatory decisions regarding capital structure. To be specific, it is appropriate and necessary for regulatory policy to accurately capture the means by which Florida Public Utilities Company underwrites its assets and rates within the regulatory capital structure, providing that such structure contains an appropriate balance of equity and debt, given the regulatory and operational business risks facing the Company. Contemporary market risks and financial risk in particular, are confronting energy utilities and corporate entities generally are at unusually high levels currently.

Year-End Capital Structure vs. Average Capital Structure. This issue, we believe, is a matter of which approach, year end or average, is most representative on a forward-looking basis beyond 2009? As shown in Exhibit 1, the 13-monthly capital structure for 2009 for Florida Public Utilities Company, when stated on a regulatory and conventional basis, contains equity participation of 42% and 48%, respectively. In contrast, as a result of the projected issuance of common equity shares at mid-year 2009, equity participation of the regulatory and conventional capital structures rise to 46% and 53%, respectively.

In brief, the average monthly-balances based capital structure understates equity participation, leaving the Company with in an inherent shortfall in the return to capital with respect to the underlying cost of capital, other factors held constant. Essentially, the Company's returns fall short, over the period over which the retail prices will be in effect. The appropriate correction of the overall cost of capital for the Company, which is inherent with the use of average capital balances in the face of the pending issuance of new shares, is to use a year-end capital structure.

Exclusion of Flo-Gas Balances. Generally speaking, in the absence of large-scale subsidiary operations, the Florida Commission should utilize a consolidated capital structure where such an approach provides a reasonable balance between debt and equity. Under such conditions, the Commission is assured that the service provider is, in the best interest of retail consumers, underwriting its assets dedicated to providing utility services at least cost.

The above principle can be viewed as a criterion for regulatory bodies and service providers to gauge the appropriateness of the proposed capital structure for determining regulated prices. As a general rule, regulatory decisions should deviate from a consolidated capital structure only when this condition—*i.e.*, an appropriate balance between debt and equity—is not satisfied. The corollary is that regulatory agencies have no foundation for removing or adding capital balances under the condition of an appropriately balanced capital structure, stated on a consolidated basis. Two facts of financial accounting underlie this corollary, as follows:

1) A firm cannot ever trace and identify, as a matter of dollar flows, specific sources of funds to specific uses of funds. The firm carries a pool of liquid funds in the form of cash and cash equivalents that vary continually as a result of inflows and outflows. One cannot say that a specific source of funds is earmarked for a specific use. As an example, one cannot say

that cash flow returns and operating income that arise from the Company's natural gas operations are used solely to underwrite resources for the natural gas business. Natural gas-sourced cash flows are, in fact, used across the combined operations of the natural gas, electricity, and propane businesses of the Company—and similarly for the electricity and propane operations.

2) The Company's balances of long- and short-term debt, preferred stock, and common equity stated on a consolidated basis represent the accrual over years of the net flows of funds of the Company including external and internal sources. The balances for these financing vehicles can and should be used as the basis by which the Company underwrites any and all of its assets, stated on either a consolidated or an individual basis. This is simply a business, accounting, and financial fact.

Exclusion of Flo-Gas balances from the capital structure used to set prices for the Company's regulated operations, including the natural gas and electricity divisions, raises issues of market competitiveness. That is, assigning common equity exclusively to the Company's unregulated propane operations places the propane business at a competitive disadvantage with respect to other propane companies. One can expect that other companies will leverage assets in a manner similar to that of the Company, in order to finance propane and other non-regulated energy services. As a consequence, the Company needs to follow a similar policy. If the Company is required to assign equity exclusively to non-regulated operations, it is implicitly forced to charge correspondingly higher prices in order to generate adequate returns to the capital committed by shareholders.

The consolidated capital structure of Florida Public Utilities Company for 2009, including Flo-Gas balances, presents a sound balance of debt and equity financing that fully satisfies the financial needs of the Company, particularly in view of the comparatively small size of Florida Public Utilities. This is evidenced by the comparative sample of natural gas utilities used to determine the cost of capital. Specifically, equity participation within the Company's 2009 capital structure resides within one standard deviation of the average participation of both the gas and electric utility samples used to estimate the cost of equity. Hence, the Company's financing policy and strategy conforms to a standard of reasonableness.

In conclusion, the recommended weighted-average cost of capital presented within our testimony follows the Commission's prescribed approach. Namely, the capital structure is based on forward-looking 2009 average balances, excluding Flo-Gas balances from common shareholder equity. However, we request that the Commission take note of the reasoning for the potential use of the consolidated capital structure including Flo-Gas balances.

Q. Would you please review interest coverage requirements, and the implications for sufficient coverage under the proposed overall rate of return?

A. Interest coverage refers to the times that debt interest is covered by income, and is generally viewed as the most important measure of investment risk of corporate debt. Interest coverage is a major concern of Florida Public Utilities Company as it is the basis for the Company to maintain its favorable credit standing with markets and to continue to raise long- and short-term debt at favorable rates of interest. Interest coverage (after tax) under the recommended capital structure and rate of return for the Company's consolidated natural gas services business unit is estimated to be 2.32 in 2009, which compared to 1.52 times for 2007 for the Company as a whole, shown in Exhibit 23.

For purposes of comparison, we also show in Exhibit 23 interest coverage over the historical timeframe 2003-2007. As can be seen, realized coverage for the Company, stated on a before tax and after tax basis, has been 2.02 and 1.66 times interest. This experience implies that the coverage implied by the recommended rate of return is adequate, though not at a robust level. Two conclusions emerge:

1) While the implied coverage level is acceptable, the Company must sustain a consistent flow of earnings in order to maintain adequate coverage and to satisfy debt covenants.
2) Contingency events and business conditions that give rise to sudden and unexpected changes in revenue or cost flows can imply an immediate shortfall in coverage. In short, the coverage level obtained

from earnings at the recommended rate of return is only adequate within today's environment of higher capital risks.

The importance of coverage cannot be overstated. Lending entities, private investors, and investment banks continue to emphasize the importance of consistently-realized adequate interest coverage as the essential measure of the Company's capability to service long- and short-term corporate debt.

Coverage is the Company's window to access capital at favorable rates of interest and under reasonable terms so that the Company can continue to fund ongoing capital investment in natural gas services. Setting the overall rate of return at a satisfactory level of 8.74% is necessary and in the best interest of natural gas consumers.

As can be seen, the recommended rate of return requirement, 8.74%, appears to provide satisfactory interest coverage. And although the overall return recommendation provides adequate coverage, it is certainly not abundant. Hence, it is absolutely necessary that Florida Public Utilities Company realize adequate and sustained flows of income to ensure that the Company satisfies credit risk requirements.

NATURAL GAS MARKETS AND CAPITAL RISKS

Q. Natural gas is an integral part of primary fuel markets and central to the nation's energy system, particularly in view of the large expansion of natural gas used for electricity power supply. Would you please provide a profile of contemporary natural gas markets and the implications for natural gas distribution and the cost of equity capital?

A. Infrastructure industries, including the electricity services industry, are undergoing significant restructuring with no immediate end in sight. For our purposes, natural gas restructuring reaches back to the Natural Gas Act of 1978 with the implementation of tiered pricing of wellhead gas. Such an approach proved disastrous, and natural gas production was subsequently deregulated in 1987. Simultaneously, Order 636 of the Federal Energy Regulatory Commission unbundled wellhead gas from the transport services provided by pipelines, with the end result being functional separation. Production moved forward as a competitive industry while pipeline services remained regulated at the national level, and natural gas distribution continued to be regulated at the local state level.

In more recent years, the rapidly expanding use of natural gas for electric power production, coupled with limited increases in domestic gas supply, has resulted in sharply higher prices for gas. Comparatively tight supply-demand conditions mean that, natural gas prices vary considerably with respect to modest changes in demand attributable to variations in weather conditions. Abnormally cold weather in winter and extreme heat in summer drive demand and prices higher, while moderate weather reduces the level of demand and prices, other factors constant. Gas prices are also sensitive to supply disruptions, such as that experienced during the late 2005 as a result of violent hurricane activity in the Gulf of Mexico. Month-ahead Henry Hub prices reached over $13/MCF in December 2005. In brief, high and widely varying prices leave natural gas distribution companies with the potential for reduced sales levels as a result of sale compression. Finally, we note that, since about 2005, the fast rising costs for equipment for replacement as well as expansion of current capability can leave natural gas and electric utilities in conditions of chronic earnings shortfall.

Q. How is this general discussion of market risks facing utilities relevant to Florida Public Utilities Company and the fair rate of return?

A. Because the cost of capital is positively related to risks, it is important that regulatory review properly account for capital risks in the determination of fair rate of return. These principles have been closely adhered to in Florida thus demonstrating continuity of regulatory policy. Furthermore, a regulatory environment that adheres closely to fair rate of return principles, including recognition of changing conditions of capital market risks, obtains benefits for retail consumers by ensuring ready access to credit markets at appropriately favorable rates.

METHODOLOGY: COST OF EQUITY CAPITAL

Q. You briefly mentioned methods for the determination of the cost of common equity capital in the summary of your return on equity recommendation. Would you please elaborate on the technical methods?

A. It is useful to reiterate three essential points identified above. First, the cost of equity of the firm—and of investors in the firm—is a function of perceptions of risk, the demand for and supply of capital, and expectations of inflation. Second, the cost of common equity of the firm is equal to the opportunity cost of capital incurred by common shareholders of the firm contemporaneously, although the experience of long-term history guides the assessment of opportunity costs. Third, the cost of equity of the firm is equal to the expected market rate of return on alternative investments of comparable risk available to shareholders—*i.e.,* the opportunity cost of capital—within a contemporary timeframe.

For two fundamental reasons, the determination of the opportunity cost rate for equity capital is challenging, and somewhat removed from the analytical procedures used to determine the cost of debt. In the case of debt, both the market price and future expected cash flow returns associated with debt securities are generally observable, by inspection. Thus, the net expected yield to maturity, which reflects the opportunity cost of capital to holders of debt, can be determined directly. This *is* the market rate of return, *ex ante*. For purposes of determining the overall utility rate of return, however, the cost rate of long-term debt is that which is set at the time of debt issuance in primary financial markets.

In contrast, expectations of investors about the prospective cash flows and market returns on common equity cannot be observed directly, and must be inferred using estimation procedures. Also, the allowed equity rate of return is typically set according to the current and expected cost of capital, though much of the equity investment was committed in many years past. That is, the cost of equity may change over time significantly—and rapidly—as market conditions change even though the original equity contribution remains static. In the determination of the cost rate for debt obligations, investors' perceptions of risks are implicit in the primary and secondary market prices of the debt obligations themselves, and need not be known or even estimated. In contrast, the determination of the cost of common equity involves the perceptions of future risks harbored by investors, as a matter of the consensus view. Perceptions of risk are also not observable directly, and thus must be inferred. In short, the cost of common equity can only be discerned through the proper and careful application of well-established methods that provided by modern finance theory. These methods involve procedures to determine the cost of equity capital via the estimation of key parameters.

In order to develop our recommendation for the rate of return on equity for Florida Public Utilities Company, we apply four estimation methods. These procedures include variants of the constant growth *Discounted Cash Flow* model ("DCF"), and the *Capital Asset Pricing Model* ("CAPM"). These classical approaches are commonly recognized within modern finance theory and are readily utilized for purposes of capital valuation. The results of these two formal models of the cost of capital are augmented by an assessment of

Realized Market Returns for utility and non-utility companies of comparable risks, and estimates of cost of capital inferred through the *Risk-Premium* methodology. The four methods are discussed below.

Q. Would you please describe the *Capital Asset Pricing Model* approach?

A. The Capital Asset Price Model (CAPM) was developed by William Sharpe (1961) and John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular, portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk-free returns and an *adjusted risk-based return.* Surrogates for risk-free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns on government debt obligations serve as appropriate surrogates.

The adjusted risk-based return is based upon three factors: 1) the covariation of the returns to the asset with that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the *difference* between expected overall returns on risky assets, and risk-free returns. The third parameter is referred to as the excess return, and is equal to the difference between the overall returns to risky assets for the market as a whole, and the risk-free return rate. The CAPM is shown below:

$$k_{e,j} = r_f + B_{jm} * (r_m - r_f) \qquad \text{with, } B_{jm} = \sigma_{jm}/\sigma_m^2$$

with,

$k_{e,j}$ = cost of equity capital for risky asset *j*, stated in percentage terms

r_f = risk-free rate of return

B_{jm} = ratio of the co-variation between risky asset *j* and the market as a whole, σ_{jm}, and the variance of market returns, σ_m^2

r_m = expected rate of return on equity markets, as a whole.

A generalization of the CAPM framework, referred to as Arbitrage Pricing Theory ("APT") has been increasingly applied in recent years.

Q. Would you please describe the *Discounted Cash Flow* model approach?

A. The constant-growth Discounted Cash Flow model was originally developed by Myron Gordon in 1957, and was advanced actively during the early 1960s. In its classical (one-stage) form, the derived DCF model defines the cost of capital as the sum of the adjusted dividend yield, and expectations of future growth in cash flows to investors including dividends and future appreciation in share prices. The classical DCF model is as follows:

$$k_{e,j} = D_{0,j}(1 + E(g_j))/P_{0,j} + E(g_j)$$

with,

$k_{e,j}$ = cost of equity capital, asset *j*

$D_{0,j}$ = current dividends per common share, asset *j*

$E(g_j)$ = expected growth in future cash flow returns to investors in asset *j*

$P_{0,j}$ = current price per common share, asset *j*.

The one-stage form of the DCF approach is an elegant and intuitively tractable model with two terms, a mathematical result derived from the constant growth present value model. A cursory review of historical returns on equities suggests that, to a substantial extent, differences in the observed internal returns to capital, as well as expectations of future returns as expressed by security analysts, contribute to realized market appreciation as well as total returns to capital. It is plausible that the *expected path* of future returns harbored by investors may assume a pattern of non-constant growth. This means that, at least under some market conditions, the constant growth form of discounted cash flow may not represent investor expectations of growth with sufficient accuracy. Arguably, other forms of DCF may serve as better approximations of investor expectations.

A plausible means to better model expectations of varying future growth might be with stochastic models, where the path of returns and growth is a function of time, with a random component. However, stochastic models introduce considerable complexity. As a first-order approximation to stochastic processes, multiple-step constant growth models known as multi-stage DCF can serve nicely. Essentially, multi-stage DCF is a variation of present value theory which postulates that future returns assume a pattern of several growth steps or stages. While any number of stages of constant growth are possible, two or three stages are typically applied. In stylized fashion, the Three-Stage DCF model is shown below:

$$P_{0,j} = (1+g_j)/(k_{e,j}-g_j)\{D_{0,j}(1 - F^5{}_j) + D_{5,j}(F^5{}_j - F^{10}{}_j) + D_{10,j}(F^{10}{}_j)\}$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{t,j}$ = current and future dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

$$F_j \quad = (1 + E(g_j))/(1 + k_{e,j}).$$

As shown in the above formulation for the Three-Stage DCF, discounted prospective cash flows are represented by three terms that incorporate the factor "F", each of which is differentiated by expected growth (*E(g)*). In the Three-Stage approach—should we say multi-stage approach—investor expectations of future growth are differentiated among time frames. Unlike the single-stage DCF approach, the estimated cost of equity capital solution to the multi-stage model (the discount rate *k*) is obtained through a mathematical search procedure that iteratively searches for the discount rate that balances the left- and right-hand-sides of the equation.

The efficient market hypothesis plays an essential role in the determination of the cost of capital. Specifically, the working assumption, which is largely though not completely borne out by empirical analysis, is that capital markets are fairly efficient. This means that the supply and demand for risky financial assets, as reflected in bid and asked prices to buy and sell shares, result in financial assets being traded at price levels where *rates of return above the cost of capital cannot be systematically realized.* Above-normal returns—returns above the cost of capital—are realized only randomly. Essentially, the opportunities to systematically realize returns above the underlying cost of capital are exhausted by the competitive market process.

Estimating the cost of capital, though not trivial, can be fairly straightforward, and both the DCF and CAPM approaches provide a useful framework. The risks to investors in various sectors of the energy services industry cannot ever be observed directly; risks—and hence the implied cost of capital—can only be inferred. Specifically, the determination of useful estimates of the cost of common equity capital within either framework requires a discerning application of theory through careful analysis. Both approaches are forward looking and thus the results are highly dependent upon useful estimates of investor expectations about future market performance.

The underlying assumptions for DCF and CAPM include, among other things, an efficient market and rational behavior of investors such that all opportunities for above- and below-normal returns to capital, over longer periods of time, are exhausted on an expected value basis. In short, capital markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

It is useful to mention that the notion of *risky assets* can also be applied to any real or financial asset wherein the prospective returns from holding the asset are uncertain. Risky assets include commodity contracts, financial property rights, financial derivatives, and real assets such as power delivery and generation facilities of electric utilities. Risk assessment and option theory, moreover, can be applied to the analysis of unbundled services, such as electricity transmission development plans. Within the context of this discussion, however, the term "risky assets" refers to the financial obligations of firms—common stock—and "asset values" refers to prices of common stock as observed on major stock exchanges.

Q. Would you please describe the *Risk Premium* approach?

Observed historical returns and future expected returns of financial assets are ordered according to risks. This ordering according to risks is a natural and inevitable result of competitive financial markets: because risk is costly, higher costs must be offset by higher returns. While it is not based upon an explicit model, the analysis of the risk premia among classes of risky assets provides a means to infer the underlying opportunity cost of capital. The underlying concept of the *Risk Premium* approach is that *differences* in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns—*i.e.,* risk premia—can thus serve as a surrogate for the compensation for risk over future timeframes. When combined prospectively with the expected cost of short-term debt, risk premia provide a useful benchmark to gauge the underlying cost of equity capital. The immediate application of the Risk Premium approach is codified as follows:

$$k_{e,j} = r^{st}{}_f + rp_{int-st} + rp_{m-int} + rp^{CAPM}{}_{y-m} + rp^{s}{}_j$$

with,

$k_{e,j}$ = cost of equity capital for risky asset j, stated in percentage terms

$r^{st}{}_f$ = risk-free rate of return, for a short-term asset

rp_{int-st} = risk premium for intermediate-term asset *int* with respect to a short-term asset

rp_{m-int} = risk premium for equity market m with respect to an intermediate-term asset

rp^{CAPM}_{y-m} = risk premium for industry y with respect to equity market m, where y refers to the relevant industry sample

rp^{s}_{j} = size-based risk premium for risky asset j.

Application of the Risk Premium approach contains three potential pitfalls. First, the opportunity cost of common equity capital, stated in nominal terms, is sensitive to the demand for and supply of capital. Second, risk premia among debt and equity instruments are also quite sensitive to expected inflation, and thus Risk Premium analysis must account for expected inflation in the future. That is, the underlying rate of inflation and conditions of the historical period over which risk premia are estimated must match those of the expected conditions of the relevant period over which the common equity recommendation is being applied, and over which retail natural gas prices are being set. Third, a debt-equity risk premium offsets inflation. General stability of prices reinforces real economic performance and productivity which, in turn, improves profits and returns to capital.

Q. Would you please describe the *Realized Market Returns* approach?

A. Measurements of *Realized Market Returns* and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that *all* financial assets are priced at levels such that the *expected* future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the *Realized Market Returns* methodology can be viewed as a market-based approach of Comparable Earnings, and thus fully satisfies the *Bluefield* and *Hope* criteria. More specifically, the realized market return for a period is defined as:

$$\boldsymbol{R_{j,\,t-t\text{-}1} = (P_{j,\,t} + D_{j,\,t-t\text{-}1} - P_{j,\,t\text{-}1})/P_{j,\,t\text{-}1}}$$

with,

$R_{j,\,t-t\text{-}1}$ = return realized within the interval $t - t\text{-}1$, for financial asset j

$D_{j,\,t-t\text{-}1}$= dividends paid during the interval $t - t\text{-}1$, f or financial asset j

$P_{j,\,t,\,t\text{-}1}$ = market value of financial asset j, at t and $t\text{-}1$.

The key to successfully applying this fourth approach is identification and measurement of historical returns in a manner that reasonably reflects expectations of investors about the future outlook.

SELECTION OF COMPARABLE RISK UTILITIES AND TIMEFRAME

Q. You discuss the importance of comparability and measures of risk as the basis to determine the cost of common equity. Please elaborate.

A. As defined by the "Bluefield" and "Hope" decisions of the U.S. Supreme Court, a public utility (to paraphrase) is entitled to a rate of return on shareholder capital committed for the convenience and necessity of the public equivalent to that realized by companies in other businesses of comparable risk. Thus, the immediate task at hand is comparability: to identify and select companies of comparable business, regulatory, and financial risks to that of Florida Public Utilities Company. Once selected, we estimate the cost of common equity for the sample(s) of comparable companies that, by definition, is the opportunity cost of capital and thus the cost of capital to Florida Public Utilities Company. The starting point is the market portfolio; that is, we begin with virtually all common shares traded on U.S. equity markets from which we proceed to select comparable risk utilities and companies. Once selected, we then estimate the cost of common equity for the sample(s) of comparable companies. A key distinction regarding comparability is market size. As recent empirical evidence convincingly demonstrates that, predominantly because of information inefficiencies and uncertainty, the cost of capital rises as firm size declines all other factors held constant.

For samples of U.S. companies, the cost of equity study draws heavily, although not exclusively from a general set of data and information sources including Value Line data banks, Ibbotson Associates (Morningstar), and the web-based services of Yahoo Finance, UBS Financial Services, and Zacks Financial Services. With few exceptions, the equity shares of the sample are traded on the NASDAQ electronic exchange, which originated from the over-the-counter trading procedures put in place by the National Association of Securities Dealers in years past, as well as the New York Stock Exchange. For these equity listings, a wide range of financial data, business descriptions and classifications, historical price experience, and various diagnostic statistics of interest are reported.

From the U.S. market portfolio, two utility company samples are obtained. The first sample (Sample 1), referred to as "moderate-sized gas distribution utilities," is composed of retail natural gas service providers. The second sample (Sample 2) referred to as "mid-sized electric utilities", is limited to retail electricity service providers that have modest yet significant levels of market participation and, with the exception of size-related capital risks, are of comparable risk to that of FPU. Our studies demonstrate that, as a practical matter, the level of capital risks (and thus the opportunity cost of capital) for the two samples, gas distribution utilities and electric utilities, is comparable.

We wish to mention that the approach to selection of companies of comparable risk and the cost of capital methods tend to demonstrate that, particularly within contemporary capital markets with high levels of international capital flows, comparable risk is the predominant selection criterion. Line of business appears to have only a modest level of relevance to cost of capital, once the comparable risk criteria are satisfied. This means that samples can be drawn from a broad range of business fields providing that comparable risk metrics are applied.

The determination of the first sample, moderate-sized gas distribution utilities, involves two steps. The first step is to conduct an initial screen according to the predefined selection criteria. As mentioned, these criteria are as follows:

Liquidity: companies that are of modest size but yet have sufficient market presence and participation to ensure sufficient market activity and transaction volume;

Business Line: companies whose primary business line is retail natural gas distribution services; and,

Reasonably consistent financial performance.

To determine gas companies for Sample 1, the study begins with 27 mid-sized entities within the U.S. gas distribution sector. For cost of capital analysis, 15 gas distribution companies are selected from this initial set, where the criteria for selection are completeness and consistency of reported financial information and market data, as well as having the gas distribution business as the primary business line. Some of these gas distribution companies have involvement in non-gas distribution activities including energy services, propane operations, and non-energy related business lines. It is virtually impossible these days to assemble a good sample of companies that are exclusively in the retail natural gas business—sometimes referred to as a *pure play*. The increased openness of U.S. utility markets in recent years, including market entry as well as relaxation of financial restrictions, has resulted in an expanded range of business activity. This new diversity should not matter, at least on the surface, if the sample is determined on a basis of comparable risks. Indeed, endeavors to diversify risk through alternative business generally mitigates variation in earnings, internal cash flow, and market returns, resulting in a reduction in overall investment risk and the cost of capital.

The second selection step in determining the gas distribution utility sample applies several risk criteria. These criteria comprise four dimensions, or metrics:

Equity Participation in Total Capital;

Coefficient of Variation in Earnings per share over five and ten years;

CAPM beta which, as discussed above, is the ratio of the covariation of the market returns of a specific stock of a company with the market as a whole, to the statistical variance of the returns of the market; and,

Variation in Market Returns, which is measured as the coefficient of variation of monthly market prices—essentially, an index of volatility in market value (market capitalization).

It is useful to mention that the mean-variation *theory* on which the Capital Asset Pricing Model is based suggests that risk metrics other than CAPM beta do not matter for the determination of portfolios that efficiently trade off risks and potential future return levels. However, other considerations are readily apparent and relevant. First, empirical evidence suggests that internal financial metrics such as the first three items above are also utilized by investors to value equities. Second, CAPM theory (as with other capital market theories) does not necessarily explain historical market returns particularly well. Thus, it appears that, to a substantial degree, information other than CAPM beta is also relevant to investors in the valuation of equities. For this reason, a set of risk metrics is used within the process of selection.

From the initial set of 15 companies, 11 natural gas utilities are selected according to comparable risk criteria identified above. The risk metrics of the selected 11 companies generally fall within one standard deviation of the average for the sample of gas utilities as first drawn or are reasonably close, for the various metrics, to the specific values for FPU.

The 15 natural gas entities have equity market capitalization ranging from $59 million to $3.1 billion during late 2007. From this initial draw, 11 entities are initially selected and, through the application of the second risk screen, eight entities are ultimately selected for use in the immediate cost of capital study. These eight gas utility companies, by this arguably objective approach, satisfy the various criteria of comparable riskiness and thus the U.S. Supreme Court guidelines regarding fair rate of return contained within the Bluefield Waterworks and Hope decisions—subject to the exception of the need for a size-related risk premium. Specifically, as with the mid-sized electric utilities of Sample 2 discussed below, these gas companies, although of comparatively modest scale by U.S. benchmarks, are all significantly larger than FPU, which implies that FPU has higher capital costs, other factors held constant.

Turning to the mid-sized U.S. electric utilities (Sample 2), the selection process proceeds in similar fashion using criteria equivalent to those employed to determine the moderate-sized gas distribution utility sample (Sample 1). Today, entities within the electricity services industry are, for example, involved in oil and gas exploration (MDU Resources), real estate (Pinnacle West), and significant non-electricity energy services (Integrys Energy). Arguably, Integrys Energy should be listed with the U.S. natural gas industry as it has substantial natural gas pipeline and distribution business lines in addition to two electric utility subsidiaries: Wisconsin Public Service and Upper Peninsula Power. However, it is still fair to say that the U.S. electric utility sample is composed of entities that have a dominant share of business activity within electric power generation and delivery.

The market capitalization of the selected electric utilities (Sample 2) measured by common shares outstanding and market prices during 2007, ranges from $74 million for Florida Public Utilities Company to about $4.8 billion for SCANA (South Carolina Electric and Gas). The non-weighted average size of Sample 2, the electric utilities, is about $1.8 billion. CAPM betas have risen over time, suggesting significantly increased capital risks associated with energy markets, including electric service providers.

The risk metrics for the 11 gas utilities are presented in Exhibits 17 and 19, whereas similar metrics for the mid-sized electric utilities can be found in Exhibits 18 and 20.

Q. You have alluded to the importance of timeframe. Please elaborate.

A. The cost of capital analyses should draw upon market experience during a timeframe that is representative and a fair match to the period for which retail utility prices are likely to be place. The issue of analysis timeframe is particularly important currently, in view of the substantial declines in the market worth of all forms of equity and debt across world financial markets. The declines have been most noticeable in December 2007—early 2008 and then again during post-August, 2008 where, since the failure of Lehman Brothers, equity and debt markets have evidenced dramatic one-day losses over successive days. It would be arguably inappropriate to sample market prices and expectations during these two timeframes—periods that harbor very high levels of capital risks and commensurate cost of capital estimates, unless the environment was expected to be sustained over an extended timeframe.

Accordingly, the immediate cost of equity study draws upon the market experience of April-May 2008, where market prices and indexes were at comparatively high levels when compared to nearby months. This sample period harbors expectations that reflect historical market returns as well as earnings and cash flow growth through 2007 and the sudden declines of the previous December. This period thus ensures that cost of capital estimates are representative and appropriate—in particular, to ensure that dividend yields and DCF-based equity cost estimates are not overstated. In short, the April-May selection period is current, reflects a sufficient level of normalcy of expected growth and perceptions of risk, and is an appropriate period to serve as the basis for estimation of the cost of capital.

COST OF EQUITY STUDY RESULTS

Q. What are the analysis results obtained from the application of the cost of common equity methodologies?

A. The task before us is to estimate the cost of capital over the relevant timeframe for which natural gas rates are to be effective. This means that the analyses should, to the degree possible, recognize future events and market conditions that might be reasonably expected by investors. The analysis of the cost of common equity is confronted with the problem of observability, which inherently results in undisclosed levels of model estimation error. For this reason, it is necessary to apply the four analysis approaches, which together provide plausible and acceptably accurate results. As noted above, these approaches are the Capital Asset Pricing Model, Discounted Cash Flow, Risk Premium, and Historical Market Returns methods. The assessment of the opportunity cost of equity capital involves gathering and processing a considerable amount of data, and using these data within structured analysis procedures that begin with sample selection, as detailed above.

Capital Asset Pricing Model. As with the other three methods, the *Capital Asset Pricing* Model is applied to both the mid-sized gas utility and electric utility samples. This approach requires estimates of the risk-free rate, investor expectations of overall market returns, and market betas which account for and embody systematic risk with reference to equity markets as a whole. Incorporating estimates of market rates of return and short-term interest rates into the CAPM formulation along with the market Betas results in estimates of the cost of common equity for Florida Public Utilities Company. The CAPM analyses for the natural gas and electric utility samples are shown in Exhibits 8 and 9, respectively.

Expected market returns for equity markets as a whole are fully captured by the S&P 500 Index when measured with the inclusion of dividend payments. The expected value of future returns of course is a key element to the application of CAPM. Plausible measures of expected market returns used in CAPM can be culled from timeframes of similar economic performance to that of the period for which the cost of capital is estimated. Specifically, the CAPM study draws upon the 1970-2007 timeframe as the basis for expected future returns. Over these 37 years, U.S. equity markets in the aggregate have obtained an overall return level of 12.6%. This timeframe includes several periods of serious contractions in market returns including 1973-1974 and 2000-2003, as well as other years of negative returns. Because the analysis is conducted in mid-2008, the results do not recognize this year's recent declines in value, which may reach 40% or greater.

Realized market returns, for monthly and annual periods as well as for decades, vary greatly, as shown within the table referred to as "Market Inputs: Dividend Yields and Overall Returns." Here, we observe significant differences in return levels experienced by investors across decades. The accompanying historical experience also appears in the table entitled "Variation in Yields and Returns" where, as can be seen toward the right, the standard deviation in monthly returns varies greatly—by over 20% during the 1970s and since 1999—the years 2000 and 2002 in particular. This level of variation for equity market returns is not unusual, and demonstrates the order of magnitude of the greater risk assumed by investors in equities in comparison to the inherent risks within debt markets, which are much lower. In short, equity market returns of well above 10% are absolutely necessary in order to compensate investors for the level of risks that they inherently assume.

Though drawn from a sufficiently long interval, this level of expected market return is not unusually high; indeed, it is significantly diminished from previous eras including the 1950s, the 1960s, and the 1994-1999 period in particular. Stated without reinvested dividends, these decade-long eras reveal overall equity market returns of close to 15%. These timeframes represent periods of overall productivity that approximates, but is arguably somewhat above, expectations of mid-year 2008, when the cost of capital was estimated within the immediate docket . Not surprisingly, productivity expectations are somewhat diminished from those of the 1950s, 1960s and the surge of the 1990s continuing into 2003-2004. Nonetheless, should expectations of future market returns be somewhat greater than the period 1970 forward, as utilized in the current study, the CAPM analyses would understate the cost of capital to Florida Public Utilities Company; conversely, lower expectations would imply that the cost of capital is somewhat overstated.

For the CAPM study, market betas for the companies of the two samples are estimated for the five-year period ending 2007. As can be observed, market betas for the sample of natural gas companies have risen significantly, from an average of 0.71 for the period 2002-2006 to 0.80 for the period ending 2007. The mid-sized electric utility sample has had a similar experience. Notably, the variation of CAPM beta across the sample of gas utilities (Sample 1, Exhibit 8) is slightly lower than that shown for the electric utility sample (Sample 2, Exhibit 9) as demonstrated by the difference between the standard deviation of the two samples. Nevertheless, the CAPM betas for 2007 for the two samples are comparable overall; hence, the two CAPM analyses produce similar cost of capital estimates. Specifically, CAPM analyses for the moderate-sized gas utility sample suggest a cost of common equity to Florida Public Utilities Company of from 9.56% to 13.26% with a weighted-average midpoint of 11.39%, stated with the inclusion of issuance costs. The corresponding analyses for the electric utilities sample obtain 9.57%-13.39% with a weighted-average midpoint value of 11.45%, also with the inclusion of issuance costs.

Discounted Cash Flow. The analysis results for the mid-sized gas distribution utilities (sample 1) and mid-sized electric utilities (sample 2) are presented on Exhibits 10 and 11, respectively. The derived form of the single-stage DCF approach is comprised of two terms, including the growth-expectation-adjusted dividend yield and investor expectations of future growth. The yield is adjusted for issuance costs of 6% to determine the final result. Analysis results are shown on a simple- and weighted-average basis, with the weights based upon the market capitalization of the sample utilities. The multi-stage DCF estimates of the cost of equity capital obtain similar results and are not shown.

The essential element for both single- and multi-stage DCF analysis is to appropriately assess investor expectations of growth of capitalization value and dividends. The analyses rely upon the historical experience of the sample companies to develop reasonable estimates of growth of internal cash and earnings. The studies generally rely on a combination of historical experience and analyst projections of cash flow and earnings growth, as implicitly contained within the valuation of investors, including larger institutions and individual investors. Timeframe is important and, for the immediate study, analyst views appear to be highly similar to those of historical experience. Also, the study relies on long-term historical experience as the basis for estimating expected growth in the future. The immediate study utilizes cash flow and earnings per share growth, which is measured in three ways. Specifically, estimates of expected growth are determined from historical growth over successive five-year periods, analyst projections of growth, and from logarithmic trend-based analysis over ten years.

For the gas utilities (Sample 1), the single stage DCF analysis suggests that the underlying cost of common equity capital resides within the range of 12.87-14.72% with an unweighted average of 13.79% before adjusting for issuance costs. The weighted-average DCF cost of equity estimate is 13.83%, also before issuance costs. With issuance costs incorporated, the result for the natural gas utilities is 14.08%, with a corresponding range of 13.13-14.97%. For the sample of electric utilities, the single-stage DCF cost of equity estimate is 11.04% with a range of 9.24-12.84%, stated on an unadjusted basis. The corresponding weighted-average cost of equity estimate 11.27% unadjusted for issuance costs. Incorporation of issuance costs of 6% obtains a cost estimate of 11.60%, with a range of 9.57%-13.17%.

We should mention that while the immediate study utilizes historical growth experience, other studies by Christensen Associates Energy Consulting, depending on timeframe, have also drawn on and applied analyst expectations of future growth within the DCF formulation of the cost of capital. Historical growth and analyst expectations of growth are positively correlated and, not surprisingly, our studies suggests that, other factors held constant, differences among the dividend yields and other metrics for companies actively traded on equity markets are explained by historical growth and analyst expectations of future growth. Generally speaking, analyst expectations are above those of historical experience. Wherein analyst projections are exclusively within DCF analyses, higher estimates for cost of common equity are generally obtained, when compared to results obtained from using the combined metrics of expected growth including history growth over successive periods, analyst projections, and logarithmic time trend (log percent change).

Risk Premium. As discussed earlier, the Risk Premium methodology infers the cost of common equity capital from the premia of realized equity returns with reference to rates of return on debt. The two cost of equity sample studies, including analysis for the natural gas utility sample and the electric utility sample, rely upon historically observed risk premia for common stocks over intermediate term government debt for timeframes that reflect the current outlook for the U.S. economy as regards to advances of productivity and real output. This analysis suggests that the overall market returns prospectively are somewhat less on average—*i.e.*, a range of 11.31% to 12.84% with a mid-point of 12.07%—across the two scenarios, than the overall market return inputs used within the CAPM analysis.

Of particular interest, these timeframes experienced modest rates of inflation, which is important to the determination of risk premia over forward timeframes. Specifically, risk premia tend to decline as inflation rises. This is because for debt inflation risk—*i.e.,* uncertainty regarding the future level of expected inflation—rises with higher inflation. Unlike equity returns which are somewhat hedged against inflation (higher nominal revenues, operating income, and net income), high inflation implies losses for debt holders. Hence, capital markets capitalize the uncertainty attending higher inflation in higher market costs of debt. Second, higher inflation appears to be commensurate with lower returns to equity holders, a result of less favorable economic conditions.

Together, risk premia tend to be significantly reduced during periods of relatively high inflation and less favorable economic and business conditions.

The manifestation of inflation risk and business conditions within risk premia between equity and debt is shown in Exhibits 12 and 13 for the natural gas and electric utility samples, respectively. The 1950s, 1960s, and 1990s reveal risk premia with respect to intermediate term debt of 10.6%-12.7%, with corresponding levels of 11.5%-12.6% with respect to short-term U.S. Treasury debt. Inflation over this period measured 2.5%. This is in sharp contrast to the U.S. experience of the 1970s and 1980s, with risk premia of 3.0%-4.3% and corresponding inflation of 5.6% for these years. The main point, for purposes of assessing capital costs prospectively, is that risk premia must be developed from historical timeframes where underlying inflation matches that of the current and prospective period for which the rate of return is being determined—2009 forward. Thus, the analyses draw risk premia from the period 1950 forward, where corresponding rates of change in overall prices were similar though somewhat above the forward-looking expected value currently. And as discussed above, these historical timeframes match the current outlook fairly well from the perspective of productivity and market returns.

The essential elements of the risk premium analysis include: 1) the risk-free holding period return, 2) the risk premia between equity and debt, and 3) cost rate adjustments for industry and size differences with respect to U.S. equity markets overall. Specifically, the approach adds risk premia to the risk-free holding period return. Consistent with the CAPM analyses, the risk premium analyses use the cost rate for 1-year Treasury securities, as expected over the prospective timeframe, as the baseline cost rate. Essentially, the cost rate for 1-year Treasury securities, for the purpose of the risk premium analysis, is the basis for the risk-free holding period return.

Debt cost rates are differentiated by term. Thus, the analyses incorporate an upward adjustment for the historical spread between 1-year and 4-year treasuries, as the historical risk premia are based upon realized market returns between equities and intermediate term government debt. Together, the cost rate one-year Treasuries, the spread between 1- and 4-year Treasury securities, and the historical debt-equity risk premia provide an estimate of the cost of common equity for equity markets as a whole. As shown in the table(s) entitled "Overall Equity Market Return" of Exhibits 12 and 13, the analysis obtains a cost of equity for equity markets of 11.31-12.84%, which confirms the historical analysis utilized in the CAPM analyses discussed above (12.60%).

Q. Do any adjustments need to be made to the estimates above to produce an accurate estimate of the cost of equity capital for FPU?

A. Further adjustments are necessary in order to assess fairly the cost of equity capital for investors in Florida Public Utilities Company, including: 1) a differential for lower market risks of utilities generally, referred to as "diversifiable risks" and 2) the small size premium (small firm effect) referred to as "small capitalization equities". The effects of these adjustments are shown in the section of these two exhibits (Exhibits 12 and 13) entitled "Cost Rate

Adjustments, Small-Sized Equities. The CAPM analysis reviewed earlier is the basis to determine how diversifiable risks associated with Samples 1 and 2, comprising the moderate-sized gas utilities and electric utilities, respectively, are below those of the composite market. The average CAPM betas of 0.82 for the natural gas utilities reduces the common equity cost rate by -1.27% to -1.57% for the gas utility sample, when compared to the expected returns to overall market. For the mid-sized electric utilities, the CAPM betas average 0.81, which implies a reduction of -1.35% to -1.66% with respect to the cost of capital for the market as a whole.

The differential for the small size premia (small firm effect) recognizes that the cost of equity is higher for small firms, other factors held constant. The small firm effect is the difference between realized market returns and the estimated cost of equity capital for small firms, as estimated by CAPM over many years. Empirically, CAPM does not explain differences in realized market returns among stocks. In particular, CAPM appears to understate systematically the realized market returns and thus the opportunity cost of capital for small capitalization entities. Exhibit 14 shows size-related risk premia for various sized firms, grouped according to market capitalization, where the small size risk premia is defined as the difference between realized market returns and CAPM-based estimates of the cost of capital. As can be observed, the small firm effect rises systematically as market capitalization declines. For FPU, underlying size-related risk premia would appear to be about 200 basis points, in the absence of other factors. As we discuss below, the size premia incorporated into the analysis takes account of the underlying systematic market risk (CAPM beta) which, for natural gas and electric utilities, is less than unity.

As shown in Exhibits 12 and 13, the small size premia can be well over four percentage points for very small-sized companies such as Florida Public Utilities Company. The Risk Premium analysis takes a conservative approach and uses the Low Capitalization Risk Premia, with a plausible range of 1.23%-1.58% for both the natural gas and the electric utility samples. Incorporating these two off-setting adjustments into the analysis across the two samples suggests that the cost of equity capital lies within the range of 10.96%-13.15% for the gas utilities (Sample 1) and 10.87%-13.07% for the electric utilities (Sample 2). Recognition of issuance expenses associated with incremental shares of common equity provides a risk premium cost of capital in the range of 12.30% for the two comparable risk samples, along with corresponding ranges of 11.21%-13.40% and 11.20%-13.40%.

The fourth analysis approach relies upon *Historical Returns* to determine estimates of expectations of future returns harbored by investors. The estimates are drawn from the historical market returns over the late-1998-2007 timeframe. This timeframe includes years of both exceptionally low and exceptionally high rates of return that, overall, are fairly well balanced. The historical realized returns for the moderate-sized gas utilities (Sample 1) are presented on pages 1-3 of Exhibit 15, while realized returns for the mid-sized electric utilities (Sample 2) are shown on pages 1-3 of Exhibit 16. For each of the two samples, historical returns are shown in three ways including "Average Returns Per

Annum" (1998-2002 – 1998-2007); "Five-Year Returns" for consecutive 5-year periods (1998-2002 – 2003-2007); and "Cumulative Returns" (1998-2002 – 1998-2007). The historical returns are determined on a simple- and weighted-average basis, where returns for the two samples have ranged from 9.81% to 10.41%. These results are conservatively stated, as the middle years 2001-2002 experienced substantial negative returns, as a result of the general equity market downturn for two years running. Historical returns realized by investors conform to the cost of capital estimates obtained by the formal cost of capital models—CAPM and Discounted Cash Flow—and by Risk Premium methods.

Q. What remaining comments do you have regarding the estimates of the cost of equity?

A. We wish to make three additional comments. First, the four methods used to determine the cost of equity—CAPM, DCF, Risk Premium, Historical Market Returns—incorporate adjustment for issuance costs of 6% of the gross proceeds for the sale of securities, which translates into about 25 basis points in the case of the gas utility sample (Sample 1), and 33 basis points in the case of the electric utilities (Sample 2).

Second, the cost of capital studies presented herein do not incorporate an allowance for market pressure or quarterly dividends. Empirical evidence suggests that market pressure is very small to non-existent, at least for larger capitalization companies. Had the analyses incorporated an adjustment for quarterly payment of dividends, the result would be—depending on perspective (frequency of payment or frequency of discounting)—to alter the estimated cost of capital by about 20-30 basis points.

Third, the cost of equity results are obtained for a sample of companies which, as mentioned, are significantly larger than Florida Public Utilities Company and, absent further adjustment for a size premia associated with very small capitalization companies such as the FPU, will understate systematically the cost of common equity capital. As we discuss above, and as presented on Exhibit 14, both intuition and empirical evidence suggests that the cost of equity is highly sensitive to the market capitalization, with very small sized firms having substantially higher opportunity costs than larger entities, other factors constant. The empirical evidence from equity markets as a whole suggests that size premia for FPU approaches 200 basis points (2.00%).

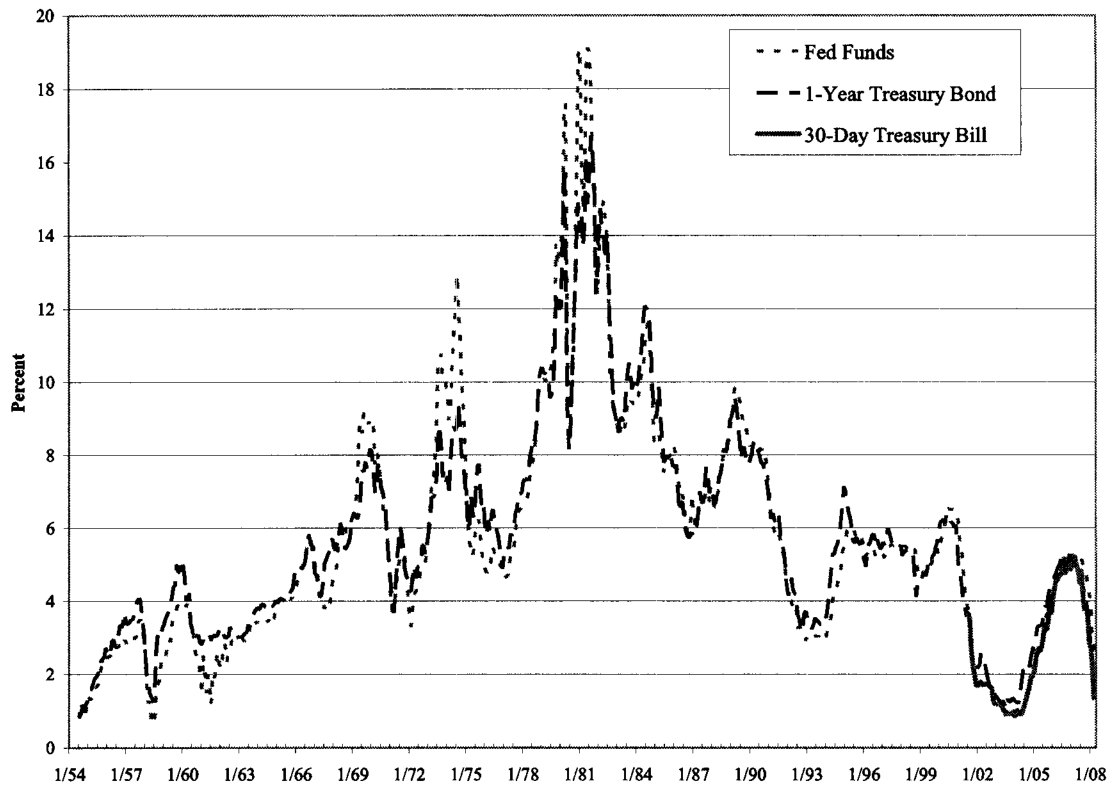
INTEREST RATES AND COST OF EQUITY CAPITAL

Q. You have implied that the cost of capital reflected in interest rates is sensitive to the demand and supply of capital, and expected inflation. Would you please provide some historical context regarding interest rate levels?

A. As mentioned, long-term interest rates follow current and expected inflation to a substantial extent, whereas short-term interest rates are sensitive to both inflation and monetary policy geared to preserving real economic growth and stability. Indeed, a major international development during the mid-1990s has been much more disciplined money supply that has resulted in a corresponding decline in worldwide inflation. Because less inflation premia is needed to compensate for the loss in purchasing power resulting from the escalation in general price level, interest rates have declined significantly.

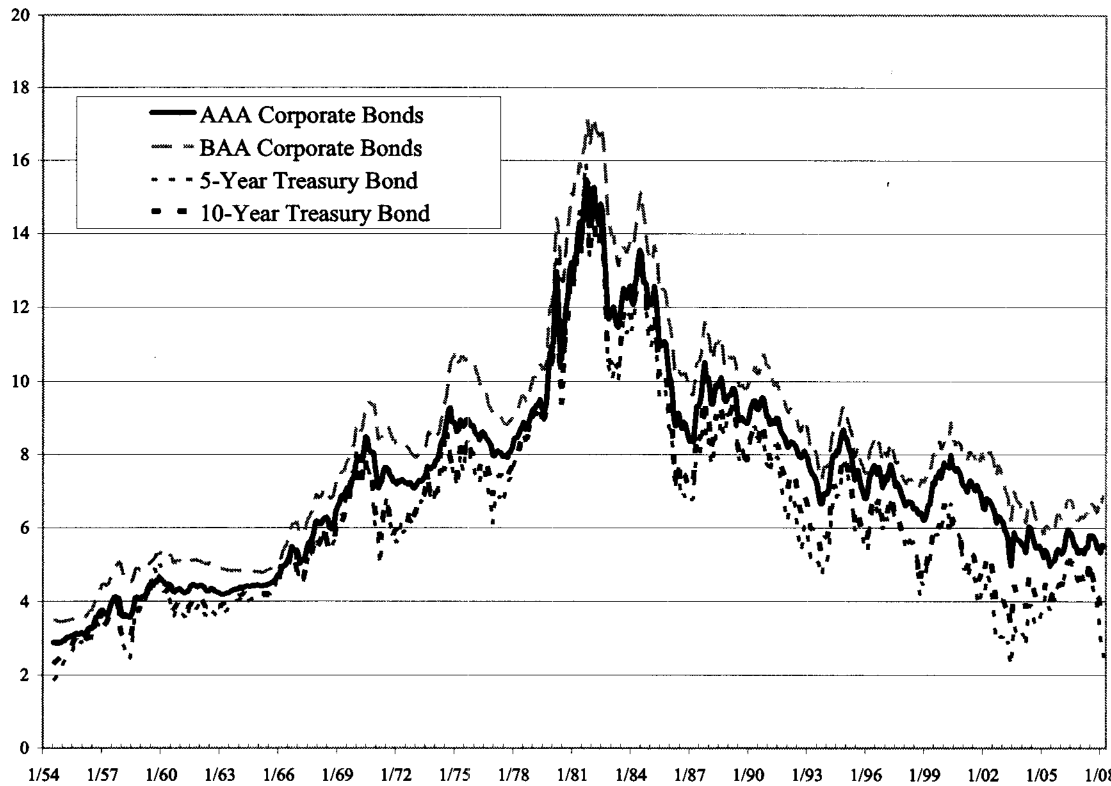
We should mention that there exists a wide range of debt mediums—and thus interest rates—across U.S. financial markets, including prime rate commercial bank loans; rated and non-rated commercial paper; constant maturity U.S. Treasury bills and bonds; Fed Funds and London Interbank Offer Rate loans of various durations; corporate bonds including debenture and mortgage debt; municipal bonds; home mortgages including variable and fixed-rate loan vehicles; and a range of securitized debt vehicles referred to as structured finance. In any case, it is useful to review the interest rate experience over both the long-term history and contemporary timeframes. Shown below are selected short- and long-term interest rates for the periods 1954 forward and 2000-2007. Short-term rates are represented by U.S. Fed Funds interest rates, and the yields for 30-Day Treasury Bills and 1-Year Treasury Bills; and long-term rates are represented by the yields for AAA-rated corporate bonds, BAA-rated corporate bonds, 5-year U.S. Treasury Bonds, and 10-year Treasury Bonds.

SHORT-TERM U.S. INTEREST RATES, 1954-2007



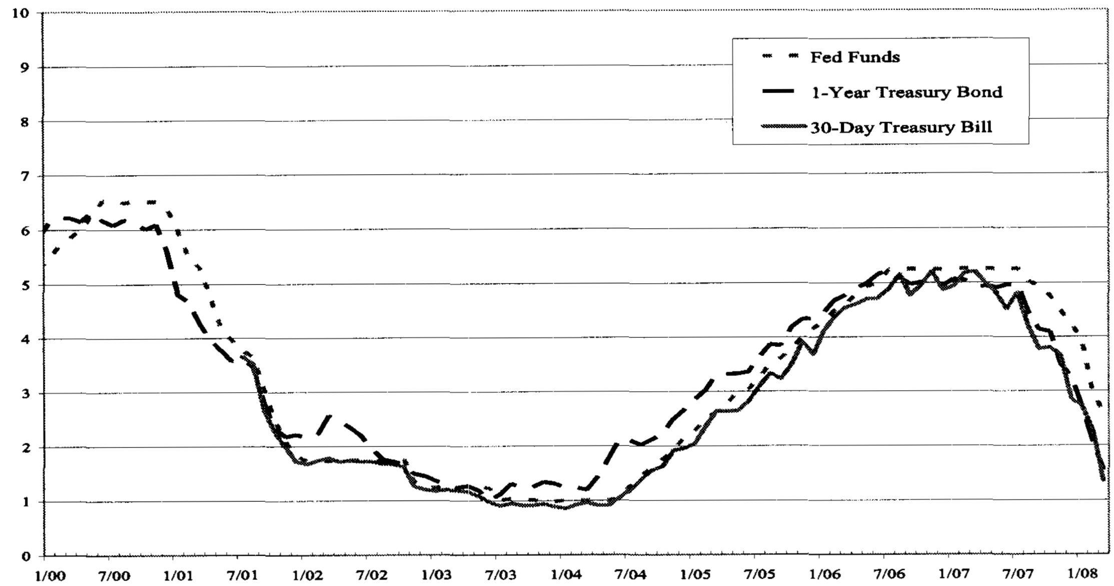
The remarkably low short-term interest rates at the beginning of the period, the mid-1950s, were a direct result of very low inflation. As can be observed, short-term interest rates prior to the early 1970s resided below 6% except for the short-lived excursion of 1969-70. In the 1970s and continuing through the recession of 1990-91, the U.S. experienced substantially higher short-term rates, typically in the range of 8-10%, with the exception of the 1979-1983 timeframe, where short-term interest rates ran briefly above 16% during an environment of highly restrictive monetary policy geared to reduce the high inflation of the period. Not surprisingly, this era of U.S. monetary history was also an era of much higher inflation, particularly during late-1970s-1985, with gradual declines thereafter. From 1991 forward, however, short-term interest rates receded back to sub-6% levels.

LONG-TERM U.S. INTEREST RATES, 1954-2007



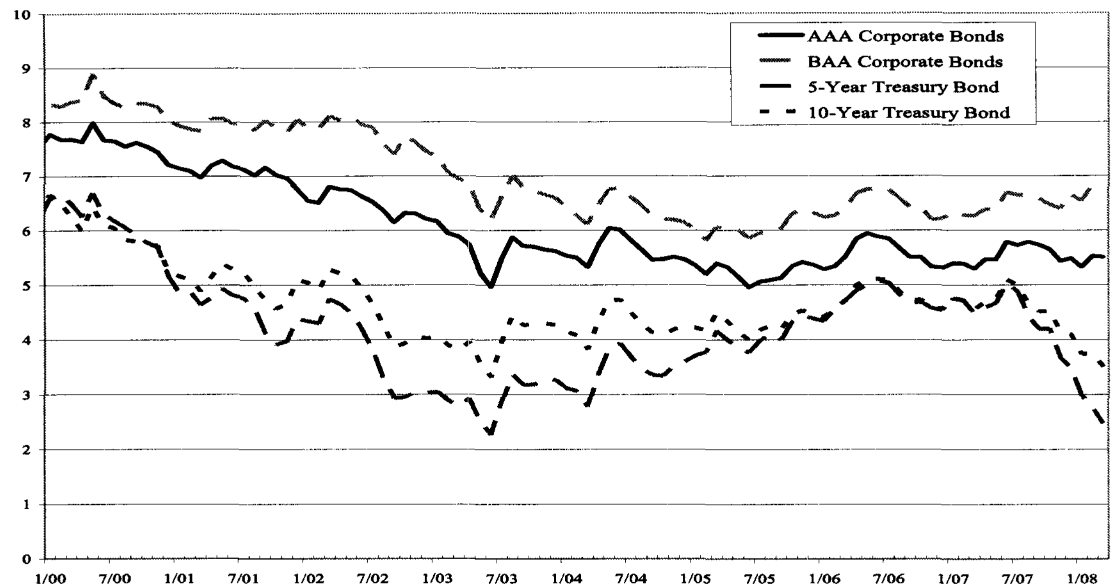
The pattern of long-term interest rates largely parallels that of short-term rates, as discussed above and shown in the previous graph. Not surprisingly, the interest rates on corporate debt consistently reside above those of U.S. Treasury debt. Most interesting, however, is the spread between corporate and treasury debt. The interest rate differences between corporate and treasury debt have increased significantly during the post-1991 period when compared to the period of comparable rates of inflation, 1954-1969.

SHORT-TERM U.S. INTEREST RATES, 2000-2007



Turning to the more contemporary period, two features are noteworthy. First, short-term interest rates, driven by expansionary monetary policy, dropped to unprecedented low rates of less than 2%, and remained at that level for the period 2002-2004. Second, beginning in late 2007, short-term rates declined precipitously, again driven by an accommodative monetary policy quickly implemented in response to the sudden decline in the level of economic activity.

LONG-TERM U.S. INTEREST RATES, 2000-2007



The essential feature of long-term interest rates currently is the increase in the interest rate spread between corporate and U.S. treasury securities, particularly for Baa bonds. Whereas long-term treasury yields, following short-term interest rates, have declined by 1.5 to 2.5 percentage points since July 2007, corporate interest rates show little movement. Moreover, corporate BAA debt yields have risen, despite the general decline in interest rates, as a result of higher perceived default risks. No doubt, the relevant development occurring just recently within the U.S. and, to a lesser extent in international debt markets, is the sharply higher default risks associated with the structured financial vehicles (asset-based financing) of various types.

Q. You have discussed why equity has higher capital risks than debt, suggesting that equity returns are above debt interest rate yields and corresponding returns. Please review.

A. Market rates of return and equity risk premia are positively related to productivity and general economic performance. The economies of North America are fairly well positioned, institutionally, to realize and sustain substantial growth in productivity and real output along with near full employment and modest inflation over the *long-term* future. The average percentage return for U.S. equity markets overall, as gauged by the S&P 500 index, was above 12.00% from 1970 through 2007, which is a period of representative levels productivity growth to gauge future potential. Contemporary high rates of productivity growth beginning roughly in 1995 were obtained through the widespread adoption of information technologies including computers, common communication, and software platforms that facilitated efficient information transfer.

An overall market return level over 1970-2007, 12.60%, is used as the expected level of future returns to equity markets within the CAPM analysis for U.S. markets, with a commensurate level of market risk premium of 7.89%. Moreover, this longer-term experience is consistent with contemporary productivity levels and realized returns to equity markets. For the U.S. economy, the average rate of observed productivity growth for the period 1970 forward resides well within the range identified above, and covers a very slow-growth period—the late 1970s to early 1980s—and the high productivity growth of 1995 through 2003. Productivity growth appears to have receded somewhat in recent years from the exceptional levels obtained during 1995-2003 timeframe. Given the relationship between market returns and productivity and other conducive factors, and because overall productivity growth over this timeframe is a reasonably close match to the expected range of productivity growth in the future (see Martin Baily, Dale Jorgenson) investors have reason to expect annual level of overall market returns to approach 11.5% to 13.0% over the foreseeable future. For U.S. equity markets, realized market returns for the period 1970-2007 comport well with realized market returns over extended periods, as shown below

Total Market Returns through 2006		
Number of Years	Initial Year	Realized Historical Annual Return (%)
81	1926	12.30
70	1937	12.30
60	1947	13.20
50	1957	11.90
40	1967	12.30
30	1977	13.60
20	1987	13.00
10	1997	12.00
Average, '67-'07		12.7
Average, '77-'07		12.9

.

However, overall economic performance and long-term growth can be attenuated by events of a transitory nature and by various long-term processes that can contribute to capital risks such as the costs to maintain environmental quality, or world-wide cultural friction. An immediate example is the decline in credit market liquidity observed in recent months. Finally, it is important to mention the impact of government fiscal policy and global demand for capital on interest rates. As mentioned, the cost of capital is a function of the demand for and supply of funds, and we expect U.S. and world demand for capital to remain at high levels, thus placing steady upward pressure on interest rates. As a result, long-term interest rates are likely to remain at or near current levels, which are close to historical experience despite recent declines in short-term interest rates.

Q. **Financial markets have been roiled by the uncertainty and risks associated with excessive levels of debt and declining asset values. Would you please elaborate on the potential impact of these events upon the cost of equity capital generally and for FPU in particular?**

A. Yes. The stresses currently being experienced by financial markets worldwide are a result of three factors. First, households in the U.S. and in some areas of Western Europe have invested heavily in residential real estate beginning in the late-1990s and extending into 2007. Rising demand for real estate was underwritten by mortgage debt which was precipitated by comparatively low interest rates. Property values rose rapidly. During late 2006 and continued into 2007 it became increasing clear that burden of mortgage debt obligations were becoming unsustainable for a large number of households.

Second, the worldwide financial sector including commercial banking and wholesale financial services were underwriting large portfolios of collateralized debt obligations, in the form of commercial mortgage-backed securities, with excessive debt leverage—in some cases with less than 5% equity participation. High levels of mortgage defaults coupled with a significant level of mortgage payments in arrears, by households, has challenged the financial solvency of many financial organizations. This condition has led to sudden and unexpected peaks in perceived debt risks, and causing very levels stress in wholesale financial markets. Third, the market value of residential properties, which provide the collateral surety for the billions of dollars of debt obligations, declined significantly particularly in southeast Florida, in the southwest including southern California, and in the United Kingdom.

These three factors have contributed to exceptionally high levels of default risks and near collapse in the level of transactions for some sectors of financial markets. In brief, the private sectors of the U.S. and world economy are in the process of deleveraging. In some instances, public and private entities particularly financial firms—and households—are unable to raise debt capital. In cases where capital is available, interest rate costs are much higher in light of exceptionally high levels of perceived risks. Going forward, long-term financing by firms, households, and local governments may require credit default insurance for many forms of debt or the pledge of assets.

The result can potentially be a calamity of enormous scale. The process of deleveraging, as we are currently experiencing, can result in a large reduction in investment of all forms including plant expansion, home remodeling, commercial real estate, public infrastructure renewal, and replacement of an aging stock of automobiles. Without a reduction in the perception of capital risk, or through public sector insurance of default risks—*i.e.*, federal home mortgage insurance—an increasingly large share of investment, for the economy as a whole, would be underwritten from current output of goods and services rather than as debt claims on economic incomes in the future. At the macro level, the transition to a substantially lower level of leverage can translate into a substantial slowdown in economy activity, potentially lasting over several years.

The consensus view holds that forestalling such eventuality requires substantial intervention by public authorities including the Federal Reserve System, the U.S. Treasury under newly authorizing legislation by the U.S. Congress, and by the Federal Deposit Insurance Corporation. So far, intervention by authorities has involved the seizure of financial institutions prior to their outright failure; special provisions to provide capital liquidity to wholesale financial markets (Federal Reserve Auction Facility); stewardship and direct oversight, including government guarantees on commitments, of the Federal National Mortgage Association and Federal Home Mortgage Corporation; purchase of commercial paper through the Commercial Paper Funding Facility of the Federal Reserve; and injections of equity capital, implemented through the purchase of convertible preferred stock, within troubled financial institutions under the Troubled Asset Relief Program operated by the U.S. Treasury.

Q. **What is the impact of the current condition of financial markets on the cost of capital?**

A. As discussed above, interest rates on debt, and the cost of capital generally, are positively related to capital risks. As revealed by bond yields on all credit rating categories of corporate debt, capital markets harbor much higher risks currently. In contrast to the recent decline in the yields on U.S. Treasury securities—because of the flight to quality and increased preferences for liquidity—Baa investment grade debt has risen to exceptionally high levels beginning in September 2008. Specifically, corporate Baa yields ranged 6.20%-6.78% during 2006 and 6.28%-6.70% during 2007, and then rose slowly during the first half of 2008. However, reflecting substantially higher risks toward the end of the third quarter of 2008, yields on Baa-rated debt for September, October, and November of 2008 rose to 7.32%, 8.88%, and 9.22% respectively. In short, corporate debt costs have risen by nearly 300 basis points, an increase of over a third within a few months.

In summary, all indications suggest that the cost of capital of the private economy, under the current stresses of financial markets and in the midst of a serious economic contraction, is somewhat above the levels for the sample period (April-May, 2008) used as a basis for the Company's cost of equity capital.

Q. What conclusions are reached by your analysis and what is your rate of return recommendation?

A. The analysis of the opportunity cost of capital incurred by common shareholders of Florida Public Utilities Company is summarized in Exhibit 6, which presents the results of the four analysis methods: the CAPM, DCF, Risk Premium, and Realized Historical Returns. The cost of equity studies are estimated for mid-sized companies that, while not large, have much larger market capitalization than Florida Public Utilities Company. The clear implication in view of the presence of observed size-related risk premia is that the unadjusted estimates of the cost of equity capital for Florida Public Utilities Company are conservative.

Mid-point values are shown in this summary, though ranges of values are presented within the exhibits presenting the detailed results for each approach. The range of estimates for the cost of equity are based on statistics drawn from the analyses themselves, and could be presented as either larger (wider) or smaller (narrower) ranges of plausible values. The analyses suggest that, for common shareholders of Florida Public Utilities Company to be adequately compensated on the capital committed to public service, and to fully satisfy the statutory requirements defined by the U.S. Supreme Court, the rate of return on common equity must be set at a level equal to 11.75% or higher.

Q. Would you please summarize your study findings and overall rate of return recommendations?

A. *Overall Rate of Return, 13-Month Capital Structure*: Following the capital structure methods prescribed by the Commission and its staff, our studies result in an overall rate of return recommendation of 8.74%. The determination of the 8.74% rate of return is presented in Exhibit 1, which reveals average balances for each financial component of the capital structure, the share that each component represents, the attending cost rate, and the overall rate of return. As discussed above, the overall rate of return recommendation is based upon a 13-month 2009 regulatory capital structure that, consistent with regulatory policy of the Commission, incorporates customer deposits, accumulated deferred income taxes, and investment tax credit balances.

Common Equity Rate of Return. The overall return level (8.74%) stated on a regulatory basis incorporates a common equity return of 11.75%. As mentioned above, the opportunity cost of capital of shareholders of Florida Public Utilities Company is assessed with four valuation methods. The cost of equity is drawn from the April-May 2008 market experience, a timeframe that is both contemporary and normal. The summary results of cost of equity studies, conducted by applying the four valuation methods to the two comparable risk samples are shown in Exhibit 6 (11.67%), along with the equity return recommendation of 11.75%.

This recommendation, if adopted by the Florida Public Service Commission, will generally enable Florida Public Utilities Company to continue to provide highly reliable natural gas service to its customers at favorable prices. At the same time, the recommendation provides an adequate level of compensation to the shareholders of Florida Public Utilities Company on the capital that they have committed to the Company. Satisfactory returns to equity also enable the Company to continue to attract long- and short-term debt at favorable terms and interest rates that, in both the near-term future and the long-run, are in the best interests of its retail natural gas consumers.

The determination of an adequate level of return on equity by the Florida Public Service Commission signals to the investment community, including mutual funds, long-term private investors, speculators, mortgage bankers, and commercial banks that the business and regulatory environment in which Florida Public Utilities Company operates has continuity and stability over the long term. Importantly, it also signals that the Commission is supportive of the Company and the job that we do on an ongoing basis for retail consumers.

Year-End Capital Structure Offered For Consideration: As discussed within our testimony, the 13-month average capital structure somewhat understates the Company's cost of capital on a going-forward basis and, for this reason, we recommend that the Commission and its staff given consideration to the year-end capital structure approach. The result of this approach is shown in Exhibit 2, where the year-end based weighted-average cost of capital is presented. Specifically, year-end balances reflect equity participation of 46% and 53% for the regulatory and traditional capital structure. This higher equity participation level translates into weighted-average cost of capital results of 8.94%, stated for regulatory purposes. In short, the average capital structure for 2009 leaves Florida Public Utilities Company short by 20 basis points, which implies an unrecognized revenue shortfall of about $240,000, stated on a going-forward basis.

The year-end capital structure is the basis by which Florida Public Utilities intends to fund its assets prospectively, and is fully consistent with the Company's business objectives of providing low-cost and reliable service. To this end, the year-end 2009 capital structure is a better representation of the expected capital structure of the Company, prospectively. In addition, the year-end balances of the components of capital provide a better balance of debt and equity for the purpose of minimizing the weighted-average cost of capital, particularly in view of the highly stressed nature of contemporary capital markets.

While the adoption of the projected year-end capital structure to determine retail prices would constitute a departure of the Commission from its general policy of using a 13-month average capital structure approach, we suggest that the year-end approach is consistent with the long-term interests of both retail consumers and the Company as well. Accordingly, we offer the year-end capital structure as an alternative to the 13-month average approach for consideration by the Commission.

At a general level, fair and adequate allowed returns to capital are vital, and we cannot over-emphasize to the Commission the importance of setting the overall rate of return at a sufficient level, particularly during in the current environment which, at the time of this writing, is experiencing major contractions in lending and investment attributable to heightened levels capital risks and economic uncertainty.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX I

PRESENT VALUE OF INVESTMENT AND DERIVATION OF THE CONSTANT GROWTH AND MULTI-STAGE DISCOUNTED CASH FLOW MODEL (DCF)

Present Value Theory

As wages are the compensation to labor, interest is the compensation or return to savings and capital. Savings is the share of current income held back to be consumed in later periods. A unit of current consumption has greater value than an equivalent amount of consumption later. Hence, savings must obtain greater consumption later, in order to compensate for its reduced (discounted) value.

The inducement to save is interest; essentially, the accrual of interest on savings offsets the reduction in value of later consumption vis-à-vis current consumption. Without the expectation of interest, savings would be largely exhausted as consumption in the current period. Savings are invested and, over time, give rise to and constitute the accumulation of capital. Savings realize the market rate of interest. Savings and investment—and thus the accumulation of capital—rise as expected interest increases.

Returns to savings, investment, and capital can be viewed as cash flow returns, and can be stated as an annual percentage amount. Cash flows in subsequent periods forego the interest that would have accrued on earlier cash flows. Because of foregone interest, later cash flows are worth less than those of earlier periods by the amount of interest that would have been realized on the earlier flows.

Cash flows over time can be ordered with a discounting procedure commonly known as present value. Present value revalues future cash flows according to the accrual of interest that would have been realized, had they occurred in the present. Specifically, the cash flow within a time step is discounted by a factor equal to the inverse of one plus the market rate of interest, *k*, compounded by time – $(1/(1+k))^t$. The present value procedure can be shown more formally as:

$$PV = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n} \qquad (1)$$

or,

$$\sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \qquad (2)$$

where,

PV = present value

CF_t = cash flow in time t

k = market cost (rate) of interest.

Hence, $1/(1+k)^t$ is the discount factor by which the cash flows at time t are reduced.

Present value analysis equates cash flows at different points in time to the present, and constitutes a fundamental principle of financial and investment analysis. Essentially, present value normalizes the cash flows at the market rate of discount.

Consider a cash flow occurring at time, $t=0$. Since the cash flow occurs in the present and, unlike the subsequent cash flows shown in (3), below, no interest is foregone and thus it is not discounted:

$$NPV = CF_o + \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n}. \tag{3}$$

Presume that a savings agent, a household, invests savings. The purchase of an investment or financial asset such as securities or other liquid assets by the agent constitutes a negative cash flow – an outflow of money. It is the expectation of positive cash flows later that induces the purchase. Positive cash flows prospectively, as expected, tend to balance the negative cash outflow associated with the purchase of the asset. All negative and positive cash flows are contained in net present value, as shown in (4) below:

$$NPV = -CF_o + \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \tag{4}$$

where,

$NPV =$ net present value – *i.e.,* the net of all positive and negative cash flows

If net present value (NPV) is positive, the investment action is "economic" in the sense that the expected positive cash flows, discounted at the market cost of capital, are greater than—or at least equivalent to—the purchase price of the asset, the negative flow.

Competitive capital markets—or the processes of market competition—seek to discover and exhaust all opportunities for positive and negative present values. That is, the *expected* NPV of investment opportunities approximates zero, given the implicit rate of discount harbored by investors. Essentially, the market value of assets is driven to its competitive level prospectively because of arbitrage inherent to competitive markets. Market forces bid prices up in the presence of expected positive returns (NPV), or bid prices down if negative returns are expected. The discounted positive cash flows equate to and balance the purchase cost of the asset, as shown in (5), below:

$$CF_o = \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t}. \tag{5}$$

In market equilibrium, then:

$$P_o = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n} \tag{6}$$

$$P_o = \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \tag{7}$$

where,

P_o = market price at time $t=0$.

The market cost of capital implicitly incorporates investor's perceptions of risk and expectations about inflation over the life of future cash flows. It is straightforward to solve for the market cost of capital, k, as we are confronted with one equation and one unknown value. For example, to solve for the internal rate of cost of a debt obligation of a borrowing firm, such as bond, simply determine the internal rate of discount that equates the positive cash flow occurring at time zero, CF_o, and the negative flows, $-\Sigma CF_t$, which represent the annual interest cost and retirement of the principle. The discounted negative cash flows from the perspective of the borrowing firm can be shown as -$\Sigma CF_t/l1+k)^t$. The analysis problem for lenders is precisely the same except that the signs attending the cash flows are reversed. Hence, the rate of discount is both the opportunity cost of capital to investors, given market arbitrage, and the cost of capital to the borrowing firm.

Constant Growth Discounted Cash Flow

For equity capital, investors' expected earnings reflect expectations of future cash flows associated with shares of stock, and thus determine the stock price currently. Assume that investors expect earnings, E_t, and dividends, D_t, to grow at some constant rate, g, over the future, such that:

$$E_t = (1+g)E_{t-1} \tag{8}$$
$$E_1 = (1+g)E_o$$
$$E_2 = (1+g)E_1 = (1+g)^2 E_o$$
$$--$$
$$--$$
$$--$$
$$En = (1+g)^n E_o.$$

Dividends of course are a function of earnings and therefore represent, along with price appreciation, the discounted cash flows. Dividends can thus be shown similarly to that of earnings, as below:

$$D_t = (1+g)D_{t-1} \tag{9}$$
i.e., $$D_1 = (1+g)D_o$$
$$D_2 = (1+g)D_1 = (1+g)^2 D_o$$
$$--$$
$$--$$
$$--$$
$$D_n(1+g)^n D_o.$$

Further, assume that dividends, D_t, are a fixed share, m, of earnings, E_t, such that:

$$D_t = mE_t \quad \text{and,} \quad D_t / E_t = m. \tag{10}$$

From equation (8), then:

$$D_t = m(1+g)E_{t-1} \tag{11}$$

and, $D_n = m(1+g)^n E_o$.

Restating equation (7) to represent dividends as a fixed share of earnings which are paid out, provides:

$$\begin{aligned} P_o &= \sum_{t=1}^{n} \frac{mE_t}{(1+k)^t} \\ &= \frac{mE_1}{(1+k)^1} + \frac{mE_2}{(1+k)^2} + \frac{mE_3}{(1+k)^3} + \cdots + \frac{mE_n}{(1+k)^n}. \end{aligned} \tag{12}$$

Observation will disclose that in fact the payout ratio is volatile and tends to offset the volatility in earnings so that dividend growth (realized cash flows) is smoothed.

Equation (12) can be restated to read:

$$\begin{aligned} P_o &= \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_n}{(1+k)^n} \\ &= \sum_{t=1}^{n} \frac{D_t}{(1+k)^t}. \end{aligned} \tag{13}$$

The relationship between D_{t-1} and D_t is simply $(1+g)$, which is also the relationship between E_{t-1} and E_t defined in (8). And, with an assumed constant payout ratio or share of earnings, the following is obtained:

$$\begin{aligned} P_o &= \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \cdots + \frac{D_o(1+g)^n}{(1+k)^n} \\ &= \sum_{t=1}^{n} \frac{D_o(1+g)^t}{(1+k)^t}. \end{aligned} \tag{14}$$

Now, assume an infinite time horizon:

$$P_o = \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \cdots + \frac{D_o(1+g)^\infty}{(1+k)^\infty}. \tag{15}$$

Equation (15) above is simply a geometric series with a growth and discounting parameter, *(1+g)/(1+k),* that defines the relative value of any two sequential terms.[1] Therefore, (15) may be expressed as:

$$P_o = \frac{D_o(1+g)}{(1+k)}\left[\frac{1-[(1+g)/(1+k)]^{\infty}}{1-(1+g)/(1+k)}\right]. \tag{16}$$

And since $[(1+g)/(1+k)]^{\infty}$ is zero,[2] and $(1-(1+g)/(1+k))$ is equal to $(k-g)/(1+k)$, the following form can be obtained:

$$P_o = D_o(1+g)/(k-g). \tag{17}$$

Multiplying through by $(k-g)$ and $1/P_o$, and rearranging gives:

$$k = D_o(1+g)/P_o + g. \tag{18}$$

This is the derived form of the constant growth Discounted Cash Flow model.

In addition, the assumption of an infinite time horizon can be relaxed. Assume that the investor has a finite time horizon, n, with a salvage value equal to P_n and a constant price-earnings ratio. Equation (14) is then restated as:

$$P_o = \sum_{t=1}^{n}\frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_n}{(1+k)^n}. \tag{19}$$

Since $P_o/E_o = P_n/E_n$, $P_n = P_o(1+g)^n$. Thus, (19) can be restated as:

$$P_o = \sum_{t=1}^{n}\frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_o(1+g)^n}{(1+k)^n}. \tag{20}$$

The first term on the right may be restated as described above, and incorporated into (20), shown below:

$$P_o = \frac{D_o(1+g)}{(k-g)}\left[1-(1+g)^n/(1+k)^n\right] + P_o(1+g)^n/(1+k)^n. \tag{21}$$

Rearranging and simplifying terms obtains:

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[1] With $(1+g) = d$, and $(1+k) = r$, a series of the form:

$$\sum_{t=1}^{n} a(d/r)^t = a\sum_{t=1}^{n}(d/r)^t.$$

This may be alternately expressed as:

$$a\frac{d}{r}[(1-(d/r)^n)/(1-(d/r))].$$

[2] If $k>g$

$$P_o - P_o(1+g)^n/(1+k)^n = \frac{D_o(1+g)}{(k-g)}[1-(1+g)^n/(1+k)^n] \quad (22)$$

or,

$$P_o[1-(1+g)^n/(1+k)^n] = \frac{D_o(1+g)}{(k-g)}[1-(1+g)^n/(1+k)^n].$$

Now, dividing both sides by $[1-(1+g)^n/(1+k)^n]$ gives an equivalent result to (16):

$$P_o = D_o(1+g)/(k-g). \quad (23)$$

Rearranging terms provides:

$$k = D_o(1+g)/P_o + g. \quad (24)$$

Thus, the constant growth form of Discounted Cash Flow is derived for a finite time horizon.

Multi-Stage DCF

The model of constant growth over the future holding period may not be a fully satisfactory representation of investor expectations under some market conditions. The constant growth form can be generalized to a varying growth path or growth with stochastic elements. Such approach increases complexity.

As a practical matter, a useful extension of the constant growth model known as multi-stage DCF can be easily developed. Arguably, multi-stage DCF presents a platform for a more accurate representation of expectations of growth harbored by investors. A derived form of the multi-stage form is developed below:

Multi-stage DCF can be shown as a restatement of Equation 14 with three patterns or rates of growth applicable to specific forward timeframes or stages:

$$P_o = \sum_{t=1}^{5}\frac{D_o(1+g_1)^t}{(1+k)^t} + \sum_{t=1}^{5}\frac{D_5(1+g_2)^t}{(1+k)^t}(1/(1+k)^5) + \sum_{t=1}^{\infty}\frac{D_{10}(1+g_3)^t}{(1+k)^t}(1/(1+k)^{10}). \quad (25)$$

Each stage can be shown in a simplified form. We begin by separating out the first stage, S_1 – *i.e.,* the first rhs term with growth = g_1 – as follows:

$$S_1 = \sum_{t=1}^{5}\frac{D_o(1+g_1)^t}{(1+k)^t}. \quad (26)$$

Pulling out the initial rate of dividends, D_0, from the sum,

$$S_1 = D_o\sum_{t=1}^{5}\frac{(1+g_1)^t}{(1+k)^t}.$$

Presenting the ratio of the growth and discount factors as a single term, $F = \dfrac{(1+g_1)}{(1+k)}$,

and incorporating F into the sum, $S_1 = D_o \sum_{t}^{5} F^t$.

The sum can then be expanded as follows:

$$S_1 = D_o\left(F^1 + F^2 + \cdots + F^5\right). \tag{27}$$

Defining a new term equal to unity, $\dfrac{(1-F)}{(1-F)}$, and including the term into the rhs of Equation 27:

$$S_1 = D_o\left(F^1 + F^2 + \cdots + F^5\right)\left(\frac{(1-F)}{(1-F)}\right), \text{ and then expanding,}$$

$$S_1 = D_o\left((F^1 + F^2 + \cdots + F^5) - (F^2 + F^3 + \cdots + F^6)\right)/(1-F). \tag{28}$$

Canceling terms of Equation 28 provides, $S_1 = D_o(F^1 - F^6)/(1-F)$, and then collecting common terms gives a simplified result, as follows:

$$S_1 = D_o F^1 (1-F^5)/(1-F). \tag{29}$$

Expanding F in Equation 28 provides,

$$S_1 = D_o\left(\frac{(1+g_1)}{(1+k)}\right)\left(1-\left(\frac{(1+g_1)}{(1+k)}\right)^5\right)\Big/\left(\frac{(1+k)-(1+g_1)}{(1+k)}\right).$$

Finally, canceling terms to simplify Equation 29 provides the result,

$$S_1 = D_o(1+g_1)\left(1-\left(\frac{(1+g_1)}{(1+k)}\right)^5\right)\Big/(k-g_1). \tag{30}$$

The above result for Stage 1 can be stated as follows,

$$S_1 = D_o\left(\frac{(1+g_1)}{(k-g_1)}\right)\left(1-\left(\frac{(1+g_1)}{(1+k)}\right)^5\right). \tag{31}$$

Note that this outcome for Stage 1 is identical to Equation 22, above.

Stage 2 of Equation 24 is:

$$S_2 = \sum_{t=1}^{5} \frac{D_5(1+g_2)^t}{(1+k)^t}(1/(1+k)^5).$$

The derived form of Stages 2 and 3 are obtained through application of the same procedures as above, and need not be reviewed. The derived result for Stage 2 is as follows:

$$S_2 = D_5\left(\frac{(1+g_2)}{(k-g_2)}\right)\left(1-\left(\frac{(1+g_2)}{(1+k)}\right)^5\right)(1/(1+k)^5). \tag{32}$$

Stage 3 of Equation 25 is:

$$S_3 = \sum_{t=1}^{\infty}\frac{D_{10}(1+g_3)^t}{(1+k)^t}(1/(1+k)^{10}).$$

Similarly, the derived form of Stage 3 is:

$$S_3 = D_{10}\left(\frac{(1+g_3)}{(k-g_3)}\right)\left(1-\left(\frac{(1+g_3)}{(1+k)}\right)^{\infty}\right)(1/(1+k)^{10}). \tag{33}$$

Note that in Stage 3, the second term in the second bracket of the rhs vanishes as a result of, by assumption, $k>g$.

APPENDIX II

Capital Asset Pricing Model (CAPM)[3]

The Sharpe-Lintner Capital Asset Pricing Model (CAPM)—William Sharpe (1964) and John Lintner (1966)—is an extension of the one-period, mean-variance portfolio model of Markowitz (1959). The Markowitz mean-variance analysis is concerned with how the investor should allocate wealth among the various assets available in the market, given that the investor is a one-period utility maximizer.

The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk free returns and an *adjusted risk-based return.* Surrogates for risk free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns on government debt obligations serve as appropriate surrogates.

The CAPM defines the market rate of return of asset j as a combination of the risk free return, R_f, and the product of a risk factor and the excess return above the risk free return, $\beta_{jm}(R_m - R_f)$. Excess return is determined as the difference between the return of the market as a whole, R_m, and the risk free return. The relevant risk factor is the well known market beta, which is defined as, the covariation of the market return of individual assets and equity markets as a whole

$$\beta_{jm} = \sigma_{jm}/\sigma^2{}_m \tag{1}$$

Start with an investment amount, I, where the share, α, is invested in asset j, and the share $(1 - \alpha)$ is invested in the market portfolio, m. The rate of return on the portfolio is,

$$R_\alpha = \alpha R_j + (1 - \alpha)R_m \tag{2}$$

The measure of variation I the portfolio returns is defined as,

$$\sigma_\alpha = [\alpha^2\sigma_j^2 + 2\alpha(1 - \alpha)\sigma_{jm} + (1 - \alpha)^2\sigma_m{}^2]^{(1/2)}. \tag{3}$$

If the portfolio share coefficient, α, is equal to zero, then the return on the portfolio is equal to R_m. This return point within rate of return – risk space is equivalent to the tangency point of market portfolio with the well-known market line.

Taking the relevant derivatives,

$$dR_\alpha/d\alpha = R_j - R_m \tag{4}$$

[3] As derived by and shown in *Investment Science*, by David Luenberger, 1998.

$$\sigma_\alpha/d\alpha = [\alpha\sigma_j^2 + (1-2\alpha)\sigma_{jm} + (\alpha-1)\sigma_m^2] / \sigma_\alpha. \tag{5}$$

For $\alpha=0$, the solution to (5) is,

$$\sigma_\alpha/d\alpha = (\sigma_{jm} - \sigma_m^2) / \sigma_m . \tag{6}$$

Defining a key relationship:

$$dR_\alpha/d\sigma_\alpha = (dR_\alpha/d\alpha) / (d\sigma_\alpha/d\alpha). \tag{7}$$

For $\alpha=0$, the above result obtains,

$$dR_\alpha/d\sigma_\alpha = (R_j - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2). \tag{8}$$

The result in (8) defines a rate of change with respect to σ_α, which must be equivalent to the slope of the capital market line. Therefore,

$$(R_j - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2) = (R_m - R_f)/ \sigma_m . \tag{9}$$

Now solving for R_j obtains the capital asset pricing model, stated in its well-known form,

$$R_j = R_f + [(R_m - R_j) / \sigma_m^2]\sigma_{jm} = R_f + \beta_{jm}(R_m - R_f) \tag{10}$$

where β_{jm} is defined as above.

In summary, the CAPM can be shown in the context of the general and well known formulation, as shown in the testimony text, where the expected rate of return is a function of risk:

$$R_j = f[E(F)] = R_f + \beta(R_m - R_f).$$

In this formulation, R_j and $f(E(F)]$ are shown to be equivalent. R_f refers to the risk-free rate of return, R_M is the market rate of return and $(R_m - R_f)$ is the market price of risk, making β the risk premium attached to holding asset j in the (market) portfolio. The essential issue, then, is whether or not the relevant risk parameter (β) adequately captures all risks, as perceived by investors. As we discuss below, recent empirical evidence challenges the notion of CAPM beta as the only relevant risk parameter.

Issues Associated with CAPM

The results of early studies of CAPM have suggested that a significant positive relationship existed between realized return and systematic risk, as measured by β, and that the relationship between risk and return appeared to be linear. However, the prediction of Sharpe-Lintner version of the model – that a portfolio or asset uncorrelated with the market should have an expected return equal to the risk-free rate of interest, have not done well, and the evidence has suggested that the average return on "zero-beta" portfolios are higher than the risk-free rate.

The first tests of CAPM on individual stock in the excess return form have been conducted by Lintner (1965) and Douglas (1968) who found that the estimated intercept is significantly different from the risk-free rate r_f and the estimate of β is statistically significant but takes a small value and the residual risk has effect on security returns. Thus, their results appear to contradict the CAPM model. However, the Douglas and Lintner studies appear to suffer from various statistical weaknesses that might explain their anomalous results. The measurement error that might be present in estimated betas in their studies could be explained by the fact that the assumptions of the regression model are not satisfied in practice.[4]

With regard to the test of CAPM in terms of stock portfolios, one classic test was performed by Fama and MacBeth (1973), who used a combined time series-cross sectional estimation to investigate whether the risk premia of the factors are non-zero. Their results showed that the beta coefficient was statistically insignificant and remained small for many sub-periods. In addition, the estimated intercept term was significantly greater than the risk-free rate, once again implying that the predictions of the CAPM might not hold.

Black, Jensen, and Scholes (1972) (Black *et al*) tested CAPM by using time series regression analysis. The results again showed that the intercept term is significantly different from zero and is time varying. They found that when $\beta > 1$, the intercept is negative and conversely when $\beta < 1$, the intercept is positive. Thus the findings of Black *et al* suggest the predictions of CAPM are not supported empirically. Stambaugh (1982) employed a slightly different methodology to test CAPM and found support for Black's version but not for the Sharpe-Lintner version. Gibbons (1982) has used a similar method as the one used by Stambaugh but instead was led to reject both standard and zero-beta CAPM formulations.

One of the principal arguments against the one-factor CAPM that uses only the market to explain excess returns is that it fails to capture the impact of other economic factors that influence investors' expected return (i.e., risk premium). Thus, another avenue of attack on the Sharpe-Lintner-Black CAPM formulations includes studies that have identified variables other than market β to explain a cross-section of expected returns. For example, Basu (1977) showed that the earnings-to-price (E/P) ratio has marginal explanatory power after controlling for β and expected returns appear to be positively related to E/P. Banz (1981) found that a stock's size (i.e., price times share) could help explain expected returns, which means that in the Sharpe-Lintner-Black framework, allowing for market β, expected returns on small stocks are too low and expected returns on large stocks are too high. Bhandari (1988) found that leverage is positively related to expected stock returns,

[4] The violations of the standard model assumptions are that the error terms are not normally distributed, not independently distributed and may be correlated with the excess market return (i.e., the explanatory variable in the regression) perhaps due to omitted variables.

and Fama and French (1992) found that higher book-to-market ratios are associated with higher expected returns in their tests that also include market β.

These anomalies of the Sharpe-Lintner-Black CAPM formulations are stylized facts that can be explained by a multifactor asset pricing model, of the type considered by Merton (1973) and Ross (1976). For example, Ball (1978) argued that E/P is a catch-all proxy for omitted factors in asset pricing tests and one can expect it to have explanatory power when an asset pricing model is expanded to include multiple factors but all relevant factors are not included in the estimated model. Chan and Chen (1991) argued that the "stock size" effect is due to the fact that small stocks include depressed firms whose performance is sensitive to business conditions. Fama and French (1992) have shown that since leverage and book-to-market equity are also largely driven by market value of equity, they may also be used as proxies for risk factors that are related to market judgments about the relative prospects of firms. One can expect when asset pricing models allow for multiple factors and, at least in theory, when all relevant factors are included in the asset pricing tests, the anomalies found in earlier work would be resolved.

The alternate approach in Chen, Roll, and Ross (1986) is to look for economic variables that are correlated with stock returns and then to test whether the loading of these economic factors describe the cross section of expected returns. This approach provides insight into how the factors relate to uncertainties about consumption and portfolio opportunities that are of concern to an investor. They examined a range of *business condition* variables that might be related to return because they are related to shocks to expected future cash flows or discount rates. The most powerful variables are the growth rate of industrial production and the difference between the return on long-term, low-grade corporate bonds and long-term government bonds. The unexpected inflation rate and the difference between the return on long and short government bonds are found to be less significant.

Merton (1973) has constructed a generalized inter-temporal asset pricing model in which factors other than market uncertainty are priced. In Merton's formulation, individuals are solving a lifetime consumption decision in a multi-period setting. He has shown that expected return on assets depends not only on the covariance of the asset with the market but also with the covariance of the asset with changes in the investment opportunity set. Therefore, Merton's formulation can be interpreted as another form of arbitrage pricing theory model. Fama and French (1992) demonstrated that two variables—size and book-to-market-equity—combine to capture the cross-sectional variation in average stock return associated with market beta, size, leverage, book-to-market ratio, and earning-to-price ratio.

In addition to the theoretical problems associated with the application of the CAPM to estimating risk premia, there are also statistical issues to be addressed. The problems of estimating and forecasting systematic risk, (i.e., beta) in the CAPM have been studied by several authors such as Lam (1999), Lally (1998), Bowie and Bradfield (1998), Boabang (1996), Draper and Paudyal (1995), Murray (1995), and Bartholdy and Riding (1994). The classical estimator for β is the well-known ordinary least squares (OLS) estimator, but several authors have shown that this estimator suffers from several deficiencies. For example, it has a mean reversion tendency, it is inefficient when return distributions are non-normal, and has significant bias problems when shares are thinly traded.

Several alternatives to OLS have been proposed in the literature. Included among these are Vasicek (1973) and Blume (1973) who both proposed estimators to improve the mean reversion tendency of the OLS estimator of β, Chan and Lakonishok (1992) proposed robust estimators to ensure more efficient estimation of β, and Scholes and Williams (1977) proposed estimators to deal with the bias problem when shares are infrequently traded. A host of empirical studies have been carried out in order to evaluate the performance of the estimators under various conditions including studies by Draper and Paudyal (1995), Murray (1995), Boabang (1996), and Lally (1998).

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EXHIBIT DC-RC 1

OVERALL RATE OF RETURN REQUIREMENTS

FLORIDA PUBLIC UTILITIES COMPANY (Natural Gas)

WEIGHTED AVERAGE COST OF CAPITAL: REGULATORY CAPITAL STRUCTURE

(2009 13-MONTH AVERAGE)

Capital Component	Amounts Balances	Capitalization Share	Cost Rate	Weighted Cost Rate
Long-Term Debt	$25,861,386	35.07%	7.90%	2.77%
Short-Term Debt	$7,363,771	9.99%	4.71%	0.47%
Preferred Stock	$320,500	0.43%	4.75%	0.02%
Common Equity	$31,130,696	42.21%	11.75%	4.96%
Customer Deposits	$6,181,495	8.38%	6.13%	0.51%
Deferred Taxes	$2,773,818	3.76%	0.00%	0.00%
ITC at Zero Cost	$0	0.00%	0.00%	0.00%
ITC at Overall Cost	$115,553	0.16%	9.38%	0.01%
Total	$73,747,220	100.00%		8.74%

FLORIDA PUBLIC UTILITIES COMPANY

WEIGHTED AVERAGE COST OF CAPITAL: CONVENTIONAL CAPITAL STRUCTURE

(2009 13-MONTH AVERAGE)

Capital Component	Amounts Balances	Capitalization Share	Cost Rate	Weighted Cost Rate
Long-Term Debt	$48,414,476	39.99%	7.90%	3.16%
Short-Term Debt	$13,785,538	11.39%	4.71%	0.54%
Preferred Stock	$600,000	0.50%	4.75%	0.02%
Common Equity	$58,279,025	48.13%	11.75%	5.66%
Total	$121,079,039	100.00%		9.38%

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EXHIBIT DC-RC 2

FLORIDA PUBLIC UTILITIES COMPANY (Natural Gas)

WEIGHTED AVERAGE COST OF CAPITAL

(2009 Year End)

Capital Component	Amounts Balances	Capitalization Share	Cost Rate	Weighted Cost Rate
Long Term Debt	$24,267,525	32.91%	7.90%	2.60%
Short-Term Debt	$5,835,722	7.91%	4.71%	0.37%
Preferred Stock	$303,838	0.41%	4.75%	0.02%
Common Equity	$33,945,973	46.03%	11.75%	5.41%
Customer Deposits	$6,386,774	8.66%	6.13%	0.53%
Deferred Taxes	$2,910,255	3.95%	0.00%	0.00%
ITC at Zero Cost	$0	0.00%	0.00%	0.00%
ITC at Overall Cost	$97,133	0.13%	9.63%	0.01%
Total	$73,747,220	100.00%		8.94%

FLORIDA PUBLIC UTILITIES COMPANY

WEIGHTED AVERAGE COST OF CAPITAL: CONVENTIONAL CAPITAL STRUCTURE

(2009 YEAR-END)

Capital Component	Amounts Balances	Capitalization Share	Cost Rate	Weighted Cost Rate
Long Term Debt	$47,921,913	37.71%	7.90%	2.98%
Short-Term Debt	$11,524,000	9.07%	4.71%	0.43%
Preferred Stock	$600,000	0.47%	4.75%	0.02%
Common Equity	$67,034,276	52.75%	11.75%	6.20%
Total	$127,080,189	100.00%		9.63%

EXHIBIT DC-RC 3

FLORDIA PUBLIC UTILITIES COMPANY

ESTIMATED EMBEDDED COST RATE OF LONG-TERM DEBT, 2009

Description, Coupon Rate	Issue Date	Life	Maturity Date	Principal Amount Sold	13-Month Average Principal Amt Outstanding	Issuing Expenses	Annual Amortization	Interest Expense	Total Annual Cost
9.57%	5/1/1988	30	5/1/2018	$10,000,000	$8,531,615	$28,562	$6,228	$816,476	$822,704
10.03%	5/1/1988	30	5/1/2018	$5,500,000	$4,692,308	$15,378	$3,354	$470,638	$473,992
9.08%	6/1/1992	30	6/1/2022	$8,000,000	$8,000,000	$52,532	$4,067	$726,400	$730,467
6.85%	10/1/2001	30	10/1/2031	$15,000,000	$14,975,000	$898,860	$40,289	$1,025,788	$1,066,077
4.90%	11/1/2001	30	11/1/2031	$14,000,000	$13,975,000	$601,084	$26,868	$684,775	$711,643
			Loss on Re-acquired Debt:			$163,031	$18,284		$18,284
				TOTALS:	$50,173,923	$1,759,447	$99,090	$3,724,077	$3,823,167
							Net Balance of Long Term Debt:		$48,414,476
						Embedded Cost Rate of Outstanding Long-term Debt:			**7.90%**

EXHIBIT DC-RC 4

FLORIDA PUBLIC UTILITIES COMPANY

SHORT TERM DEBT COST RATE, 2009

Item	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVERAGES	EFFECTIVE S-T DEBT COST RATE
LOC Available	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000		
Balance, End of Month	19,324,000	18,724,000	17,224,000	16,224,000	17,424,000	19,424,000	19,424,000	5,924,000	6,924,000	7,024,000	8,724,000	11,324,000	11,524,000	13,785,538	
Average Balance		12,711,453	11,693,124	11,014,239	11,828,901	13,186,673	13,186,673	4,021,718	4,700,603	4,768,492	5,922,597	7,687,700	7,823,477	9,045,471	
Unused LOC		13,288,547	14,306,876	14,985,761	14,171,099	12,813,327	12,813,327	21,978,282	21,299,397	21,231,508	20,077,403	18,312,300	18,176,523	16,954,529	-
Interest On															
Outstanding Balances		$ 41,842	$ 38,490	$ 36,255	$ 38,937	$ 43,406	$ 43,406	$ 13,238	$ 15,473	$ 15,696	$ 19,495	$ 25,305	$ 25,752	357,296	3.95%
Fees, Unused LOC	0.25%	$ 2,768	$ 2,981	$ 3,122	$ 2,952	$ 2,669	$ 2,669	$ 4,579	$ 4,437	$ 4,423	$ 4,183	$ 3,815	$ 3,787	$ 42,386	0.47%
Fee for LOC Available	0.10%						$ 26,000							$ 26,000	0.29%
Total Charges		$ 44,610	$ 41,470	$ 39,377	$ 41,889	$ 46,076	$ 72,076	$ 17,817	$ 19,910	$ 20,120	$ 23,678	$ 29,120	$ 29,539	**$ 425,682**	**4.71%**

EXPECTED FED FUNDS RATE:	2.98%
INTEREST RATE SPREAD, LIBOR minus FED FUNDS:	0.17%
LOC-BASED RATE ADDER TO LIBROR:	0.80%
EFFECTIVE INTEREST RATE, LOC OUTSTANDING BALANCES:	**3.95%**

EXHIBIT DC-RC 5

FLORIDA PUBLIC UTILITIES COMPANY

EMBEDDED COST RATE OF PREFERRED STOCK, 2009

Description, Coupon Rate	Issue Date	Principle	Dividends	Cost Rate
4.75% Cumulative	12/28/1945	$600,000	$28,500	**4.75%**

EXHIBIT DC-RC 6

FLORIDA PUBLIC UTILITIES COMPANY

COST OF COMMON EQUITY and EQUITY RATE OF RETURN RECOMMENDATION

METHODOLOGY	MODERATE-SIZED GAS DISTRIBUTION UTILITIES	MID-SIZED ELECTRIC UTILITIES	ESTIMATED COST OF EQUITY CAPITAL
Capital Asset Pricing Model			
Single Factor Model	11.39%	11.45%	11.42%
Discounted Cash Flow			
Single-Stage Model*	14.08%	11.60%	12.84%
Risk Premium			
CAPM-Based, Size-Premia Adjusted	12.30%	12.30%	12.30%
Realized Market Returns			
Over 5- to 10-Year Periods	9.81%	10.40%	10.11%
Market-Based Estimates			
		Average:	**11.67%**
		Cost of Equity Recommendation:	**11.75%**

* Multi-Stage DCF Approach Provides Similar Results

EXHIBIT DC-RC 7

FLORIDA PUBLIC UTILITIES COMPANY (Natural Gas)

ESTIMATED CUSTOMER DEPOSITS AND COST RATE, 2009

	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVERAGE	Interest (12 Months)
Customer Deposits	$5,980,300	$6,013,161	$6,046,203	$6,079,426	$6,112,832	$6,146,422	$6,180,196	$6,214,156	$6,248,302	$6,282,636	$6,317,159	$6,351,871	$6,386,774	$6,181,495	
Interest Expense @ 6%		$26,739	$26,886	$27,034	$27,183	$27,332	$27,482	$27,633	$27,785	$27,938	$28,091	$28,245	$28,401		$330,749
Interest Expense @ 7%		$3,881	$3,902	$3,924	$3,945	$3,967	$3,989	$4,011	$4,033	$4,055	$4,077	$4,100	$4,122		$48,005
Total Interest Expense		$30,620	$30,788	$30,958	$31,128	$31,299	$31,471	$31,644	$31,818	$31,992	$32,168	$32,345	$32,523		$378,753
														Cost Rate:	6.13%

EXHIBIT DC-RC 8

FLORIDA PUBLIC UTILITIES COMPANY

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

Electric Utilities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	**Ticker**	**2007**	**5 Year Average, 2006 Ending**	**2007**	**5 Year Average, 2006 Ending**
Atmos Energy	ATO	0.80	0.71	0.70	0.57
EnergySouth Inc	ENSI	0.65	0.56	0.48	0.34
Laclede Group	LG	0.90	0.77	0.85	0.66
New Jersey Resources	NJR	0.80	0.74	0.70	0.61
Northwest Nat. Gas	NWN	0.80	0.70	0.70	0.55
Piedmont Natural Gas	PNY	0.80	0.76	0.70	0.64
Southwest Gas	SWX	0.85	0.79	0.78	0.69
WGL Holdings Inc.	WGL	0.85	0.77	0.78	0.66
	Average	0.81	0.71	0.69	0.56
	Standard Deviation	0.07	0.08	0.12	0.11
	Weighted Average:	0.82	0.74	0.72	0.61

MARKET INPUTS: AVERAGE YIELDS AND OVERALL RETURNS

	1-Year Gov't Debt Interest Rates (%)	10-Year Gov't Debt Interest Rates (%)	1- to 10-Year Spread in Debt Rates (%)	S&P500 Total Return (%)	Chain-Weighted Rates of Inflation (%)
1950s	2.62	3.22	0.60		2.60
1960s	4.40	4.67	0.28		2.62
1970s	7.00	7.50	0.50	7.92	6.82
1980s	9.74	10.60	0.85	18.23	4.44
1990s	5.36	6.66	1.30	18.99	2.14
2000s	3.47	4.71	1.23	2.83	1.83
60s, 70s, 90s	5.58	6.28	0.74		
Overall	5.43	6.23	0.80	12.60	3.57

VARIATION IN YIELDS AND RETURNS (%)

	1-Year	10-Year	1- to 10-Year Spread	S&P500 Total Return
1950s	1.07	0.63	0.51	
1960s	1.32	0.91	0.46	
1970s	1.75	0.99	1.02	20.36
1980s	2.70	2.16	1.02	13.07
1990s	1.21	1.00	0.96	14.16
2000s	1.68	0.62	1.25	16.45
60s, 70s, 90s	1.43	0.97	0.81	
Overall	1.96	1.53	0.87	16.01

CAPM ESTIMATES: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.31%	3.94%	0.80	10.68%	3.94%
High	13.01%	5.47%	0.83	14.52%	5.47%
Weighted Average	11.14%	4.71%	0.82	12.60%	4.71%

U.S. Equity Market Risk Premia: 7.89%

	Cost Rate, Adjusted for Issuance Costs
Low	9.56%
High	13.26%
Weighted Average	11.39%

EXHIBIT DC-RC 9

FLORIDA PUBLIC UTILITIES COMPANY

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: MID-SIZED ELECTRIC UTILITIES

Electric Utilities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2007	5 Year Average, 2006 Ending	2007	5 Year Average, 2006 Ending
Hawaiian Elec.	HE	0.70	0.66	0.55	0.49
Empire Dist. Elec.	EDE	0.85	0.72	0.78	0.58
OGE Energy	OGE	0.75	0.71	0.63	0.57
Otter Tail Corp.	OTTR	0.75	0.61	0.63	0.42
CH Energy Group	CHG	0.85	0.80	0.78	0.70
Energy East Corp.	EAS	0.85	0.81	0.78	0.72
Florida Public Utilities	FPU	0.55	0.59	0.33	0.39
SCANA Corp.	SCG	0.80	0.73	0.70	0.60
UIL Holdings	UIL	0.90	0.81	0.85	0.72
G't Plains Energy	GXP	0.85	0.82	0.78	0.73
Vectren Corp.	VVC	0.90	0.81	0.85	0.72
	Average	0.80	0.70	0.65	0.56
	Standard Deviation	0.10	0.08	0.15	0.12
	Weighted Average:	0.81	0.75	0.72	0.63

MARKET INPUTS: AVERAGE YIELDS AND OVERALL RETURNS

	1-Year Gov't Debt Interest Rates (%)	10-Year Gov't Debt Interest Rates (%)	1- to 10-Year Spread in Debt Rates (%)	S&P500 Total Return (%)	Chain-Weighted Rates of Inflation (%)
1950s	2.62	3.22	0.60		2.60
1960s	4.40	4.67	0.28		2.62
1970s	7.00	7.50	0.50	7.92	6.82
1980s	9.74	10.60	0.85	18.23	4.44
1990s	5.36	6.66	1.30	18.99	2.14
2000s	3.47	4.71	1.23	2.83	1.83
60s, 70s, 90s	5.58	6.28	0.74		
Overall	5.43	6.23	0.80	12.60	3.57

VARIATION IN YIELDS AND RETURNS (%)

	1-Year	10-Year	1- to 10-Year Spread	S&P500 Total Return
1950s	1.07	0.63	0.51	
1960s	1.32	0.91	0.46	
1970s	1.75	0.99	1.02	20.36
1980s	2.70	2.16	1.02	13.07
1990s	1.21	1.00	0.96	14.16
2000s	1.68	0.62	1.25	16.45
60s, 70s, 90s	1.43	0.97	0.81	
Overall	1.96	1.53	0.87	16.01

CAPM ESTIMATES: MID-SIZED ELECTRIC UTILITIES

	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.24%	3.94%	0.79	10.68%	3.94%
High	13.06%	5.47%	0.84	14.52%	5.47%
Weighted Average	11.12%	4.71%	0.81	12.60%	4.71%
			U.S. Equity Market Risk Premia:	7.89%	

	Cost Rate, Adjusted for Issuance Costs
Low	9.57%
High	13.39%
Weighted Average	**11.45%**

EXHIBIT DC-RC 10

FLORIDA PUBLIC UTILITIES COMPANY

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend Rate	Average Market Price Per Share, April - May '08	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Atmos Energy	ATO	1.30	$1.36	$27.38	4.96%	8.78%	13.74%
EnergySouth Inc	ENSI	1.00	$1.06	$53.86	1.96%	11.43%	13.40%
Laclede Group	LG	1.50	$1.57	$38.55	4.08%	9.48%	13.55%
New Jersey Resources	NJR	1.07	$1.15	$32.31	3.55%	14.51%	18.05%
Northwest Nat. Gas	NWN	1.50	$1.57	$44.86	3.50%	9.04%	12.54%
Piedmont Natural Gas	PNY	1.00	$1.05	$26.41	3.96%	9.35%	13.31%
Southwest Gas	SWX	0.86	$0.90	$29.92	3.00%	8.89%	11.89%
WGL Holdings Inc.	WGL	1.36	$1.43	$33.50	4.25%	9.61%	13.87%

DCF ESTIMATES, MODERATE-SIZED GAS DISTRIBUTION UTILITIES

	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	3.66%	10.14%	13.79%
S. D.	0.90%	1.95%	1.84%
Range			
Low	3.21%	9.16%	12.87%
High	4.11%	11.11%	14.72%
Weighted Average	3.97%	9.86%	13.83%

Cost Rate, Adjusted for Issuance Costs

Weighted Average	**14.08%**
Range	
Low	13.13%
High	14.97%

EXHIBIT DC-RC 11

FLORIDA PUBLIC UTILITIES COMPANY

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MID-SIZED ELECTRIC UTILITIES

Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend Rate	Average Market Price Per Share, April - May '08	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Hawaiian Elec.	HE	1.24	$1.30	$25.37	5.12%	9.31%	14.43%
Empire Dist. Elec.	EDE	1.28	$1.35	$20.60	6.53%	10.29%	16.83%
OGE Energy	OGE	1.39	$1.43	$32.76	4.37%	5.47%	9.83%
Otter Tail Corp.	OTTR	1.19	$1.23	$37.16	3.30%	5.83%	9.14%
CH Energy Group	CHG	2.16	$2.18	$36.08	6.03%	1.46%	7.49%
Energy East Corp.	EAS	1.24	$1.25	$23.76	5.27%	1.95%	7.22%
Florida Public Utilities	FPU	0.45	$0.47	$11.44	4.12%	8.37%	12.48%
SCANA Corp.	SCG	1.76	$1.85	$39.33	4.71%	10.34%	15.04%
UIL Holdings	UIL	1.73	$1.73	$31.43	5.50%	-0.14%	5.36%
G't Plains Energy	GXP	1.66	$1.70	$25.74	6.60%	4.64%	11.24%
Vectren Corp.	VVC	1.30	$1.35	$28.73	4.70%	7.73%	12.43%

DCF ESTIMATES, MID-SIZED ELECTRIC UTILITIES

	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	5.11%	5.93%	11.04%
S. D.	1.02%	3.65%	3.60%
Range			
Low	4.60%	4.10%	9.24%
High	5.62%	7.76%	12.84%
Weighted Average	5.09%	6.18%	11.27%

Cost Rate, Adjusted for Issuance Costs

Weighted Average	**11.60%**
Range	
Low	9.57%
High	13.17%

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FLORIDA PUBLIC UTILITIES COMPANY

RISK PREMIUM ANALYSIS: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

Overall Equity Market Return		
Cost Rate Components	Market Return Requirements	
	Lower Bound	Upper Bound
1-Year Treasuries	2.01%	4.63%
1-Yr - 10-Yr Spread	1.18%	1.64%
Equity - T. Debt Risk Premia	7.35%	
Expected Overall Market Return	11.31%	12.84%

Cost Rate Adjustments, Small-Sized Equities		
Adjustment Component	Lower Bound	Upper Bound
Diversifiable Risks	-1.57%	-1.27%
Small Capitalization Risk Premia	1.23%	1.58%

Cost of Capital, Small-Sized Equities		
	Lower Bound	Upper Bound
w/o issuance Costs	10.96%	13.15%
Average:	12.05%	
with Issuance Costs	11.21%	13.40%
Average:	12.30%	

FLORIDA PUBLIC UTILITIES COMPANY

RISK PREMIUM ANALYSIS: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

Timeframes	S&P 500 minus Intermediate Term Debt		S&P 500 minus Short Term Debt		GDP Inflation
	Average Per Annum	Geometric	Average Per Annum	Geometric	
1950s	18.2%	16.6%	19.0%	17.4%	2.6%
1960s	4.2%	3.2%	4.8%	3.8%	2.6%
1970s	0.4%	-1.3%	1.2%	-0.7%	6.8%
1980s	8.2%	7.4%	9.3%	8.4%	4.4%
1990s	12.7%	11.8%	14.1%	13.2%	2.1%
2000s	-1.4%	0.0%	-0.4%	0.0%	1.8%
1950-Forward	7.3%				
Average, 50s-90s	8.7%	7.5%	9.7%	8.4%	3.7%
'50s, '60s,'90s	11.7%	10.6%	12.6%	11.5%	2.5%
'70s, '80s	4.3%	3.0%	5.2%	3.9%	5.6%
2000s	-1.4%	0.0%	-0.4%	0.0%	1.8%

Timeframes	Mid-Cap Size Premia		Small-Cap Size Premia		Micro-Cap Size Premia		1-Year Treasury Yields	1-Year 10-Year Spread
	Average	S.D	Average	S.D.	Average	S.D.		
1950s	1.8%	2.1%	2.3%	2.9%	3.6%	4.3%	2.6%	0.6%
1960s	3.0%	3.3%	4.5%	6.5%	8.3%	10.7%	4.4%	0.3%
1970s	3.4%	5.5%	4.6%	9.8%	5.6%	13.8%	7.0%	0.5%
1980s	2.2%	4.2%	3.6%	8.0%	2.4%	11.3%	9.7%	0.9%
1990s	-1.0%	4.2%	-1.6%	5.3%	-1.5%	8.1%	5.4%	1.3%
2000s	3.1%	4.9%	5.8%	6.9%	11.3%	11.2%	3.3%	1.4%
Average, 50s-90s	1.9%	3.8%	2.7%	6.5%	3.7%	11.0%	6.6%	0.7%
'50s, '60s,'90s	1.3%	3.2%	1.7%	4.9%	3.5%	7.7%	4.1%	0.7%
'70s, '80s	2.8%	4.8%	4.1%	8.9%	4.0%	12.5%	8.4%	0.7%
2000s	3.1%	4.9%	5.8%	6.9%	11.3%	11.2%	3.3%	1.4%
S. D. Across Decades	1.6%		2.6%		4.5%		2.6%	0.5%

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EXHIBIT DC-RC 13, Page 1 of 2

FLORIDA PUBLIC UTILITIES COMPANY

RISK PREMIUM ANALYSIS: MID-SIZED ELECTRIC UTILITIES

Overall Equity Market Return		
Cost Rate Components	**Market Return Requirements**	
	Lower Bound	**Upper Bound**
1-Year Treasuries	2.01%	4.63%
1-Yr - 10-Yr Spread	1.18%	1.64%
Equity - T. Debt Risk Premia	7.35%	
Expected Overall Market Return	11.31%	12.84%

Cost Rate Adjustments, Small-Sized Equities		
Adjustment Component	**Lower Bound**	**Upper Bound**
Diversifiable Risks	-1.66%	-1.35%
Small Capitalization Equities	1.23%	1.58%

Cost of Capital, Small-Sized Equities		
	Lower Bound	**Upper Bound**
w/o issuance Costs	10.87%	13.07%
Average:	11.97%	
with Issuance Costs	11.20%	13.40%
Average:	**12.30%**	

EXHIBIT DC-RC 13, Page 2 of 2*

FLORIDA PUBLIC UTILITIES COMPANY

RISK PREMIUM ANALYSIS: MID-SIZED ELECTRIC UTILITIES

Timeframes	S&P 500 minus Intermediate Term Debt		S&P 500 minus Short Term Debt		GDP Inflation
	Average Per Annum	Geometric	Average Per Annum	Geometric	
1950s	18.2%	16.6%	19.0%	17.4%	2.6%
1960s	4.2%	3.2%	4.8%	3.8%	2.6%
1970s	0.4%	-1.3%	1.2%	-0.7%	6.8%
1980s	8.2%	7.4%	9.3%	8.4%	4.4%
1990s	12.7%	11.8%	14.1%	13.2%	2.1%
2000s	-1.4%	0.0%	-0.4%	0.0%	1.8%
1950-Forward	7.3%				
Average, 50s-90s	8.7%	7.5%	9.7%	8.4%	2.4%
'50s, '60s,'90s	11.7%	10.6%	12.6%	11.5%	2.5%
'70s, '80s	4.3%	3.0%	5.2%	3.9%	5.6%
2000s	-1.4%	0.0%	-0.4%	0.0%	1.8%

Timeframes	Mid-Cap Size Premia		Small-Cap Size Premia		Micro-Cap Size Premia		1-Year Treasury Yields	1-Year 10-Year Spread
	Average	S.D	Average	S.D.	Average	S.D.		
1950s	1.8%	2.1%	2.3%	2.9%	3.6%	4.3%	2.6%	0.6%
1960s	3.0%	3.3%	4.5%	6.5%	8.3%	10.7%	4.4%	0.3%
1970s	3.4%	5.5%	4.6%	9.8%	5.6%	13.8%	7.0%	0.5%
1980s	2.2%	4.2%	3.6%	8.0%	2.4%	11.3%	9.7%	0.9%
1990s	-1.0%	4.2%	-1.6%	5.3%	-1.5%	8.1%	5.4%	1.3%
2000s	3.1%	4.9%	5.8%	6.9%	11.3%	11.2%	3.3%	1.4%
Average, 50s-90s	1.9%	3.8%	2.7%	6.5%	3.7%	11.0%	6.6%	0.7%
'50s, '60s,'90s	1.3%	3.2%	1.7%	4.9%	3.5%	7.7%	4.1%	0.7%
'70s, '80s	2.8%	4.8%	4.1%	8.9%	4.0%	12.5%	8.4%	0.7%
2000s	3.1%	4.9%	5.8%	6.9%	11.3%	11.2%	3.3%	1.4%
S. D. Across Decades	1.6%		2.6%		4.5%		2.6%	0.5%

*** Identical to Exhibit DC-RC 12, Page 2; Included for Convenience.**

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EXHIBIT DC-RC-14

FLORIDA PUBLIC UTILITIES COMPANY

SIZE-RELATED RISK PREMIA

Market Capitalization ($ Millions)			Equity Size Risk Premia
Deciles	**Smallest Sized Entity In Decile**	**Largest Sized Entity In Decile**	
1 (Largest)	$16,848	$371,187	-0.36%
2	$7,847	$16,821	0.65%
3	$4,098	$7,777	0.81%
4	$2,862	$4,085	1.03%
5	$1,947	$2,849	1.45%
5	$1,379	$1,947	1.67%
7	$978	$1,378	1.62%
8	$627	$977	2.28%
9	$315	$627	2.70%
10 (Smallest)	$2.200	$314	6.27%

Market Capitalization of FPU, 2006: $76.5

Size Risk Premia Relevant To
Florida Public Utilities Company: 2.20%

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EXHIBIT DC-RC 15, Page 1 of 3

FLORIDA PUBLIC UTILITIES COMPANY

AVERAGE RETURNS PER ANNUM: MID-SIZED GAS DISTRIBUTION UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
AGL Resources	8.70%	10.46%	11.62%	13.14%	12.49%	12.61%
Atmos Energy	4.49%	5.38%	6.67%	7.73%	7.15%	8.29%
EnergySouth Inc	12.79%	12.83%	15.75%	15.87%	15.62%	18.37%
Laclede Group	6.74%	7.37%	9.34%	9.74%	9.66%	9.31%
New Jersey Resources	13.86%	13.63%	14.62%	15.00%	13.86%	10.14%
Nicor Inc.	5.58%	3.52%	4.64%	6.13%	7.06%	7.20%
Northwest Nat. Gas	7.47%	6.91%	8.31%	9.74%	9.51%	11.35%
Piedmont Natural Gas	12.45%	12.18%	13.07%	13.50%	12.92%	12.65%
South Jersey Inds.	12.30%	12.89%	14.87%	16.96%	15.75%	16.83%
Southwest Gas	9.99%	7.92%	8.67%	9.13%	10.95%	10.79%
WGL Holdings Inc.	7.39%	6.47%	7.72%	8.75%	7.78%	8.34%
Average	9.25%	9.05%	10.48%	11.43%	11.16%	11.44%
Weighted Average	8.61%	8.54%	9.78%	10.84%	10.55%	10.71%
				Across Years,	**Average:***	10.47%
					Weighted:*	9.84%

COST OF EQUITY SAMPLE: MID-SIZED GAS DISTRIBUTION COMPANIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
Atmos Energy	4.49%	5.38%	6.67%	7.73%	7.15%	8.29%
EnergySouth Inc	12.79%	12.83%	15.75%	15.87%	15.62%	18.37%
Laclede Group	6.74%	7.37%	9.34%	9.74%	9.66%	9.31%
New Jersey Resources	13.86%	13.63%	14.62%	15.00%	13.86%	10.14%
Northwest Nat. Gas	7.47%	6.91%	8.31%	9.74%	9.51%	11.35%
Piedmont Natural Gas	12.45%	12.18%	13.07%	13.50%	12.92%	12.65%
Southwest Gas	9.99%	7.92%	8.67%	9.13%	10.95%	10.79%
WGL Holdings Inc.	7.39%	6.47%	7.72%	8.75%	7.78%	8.34%
Average	9.40%	9.09%	10.52%	11.19%	10.93%	11.15%
Weighted Average	8.79%	8.52%	9.74%	10.50%	10.18%	10.27%
				Across Years,	**Average:***	10.38%
					Weighted:*	9.67%

*** Unadjusted for Issuance Costs**

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EXHIBIT DC-RC 15, Page 2 of 3

FLORIDA PUBLIC UTILITIES COMPANY

FIVE YEAR RETURNS: MID-SIZED GAS DISTRIBUTION UTILITIES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2001 - 2005	2002 - 2006	2003 - 2007
AGL Resources	8.70%	11.92%	14.66%	20.32%	15.55%	16.52%
Atmos Energy	4.49%	2.00%	5.25%	12.89%	8.66%	12.09%
EnergySouth Inc	12.79%	9.55%	17.65%	21.48%	20.77%	23.94%
Laclede Group	6.74%	6.40%	10.56%	14.34%	11.98%	11.89%
New Jersey Resources	13.86%	11.51%	13.47%	15.20%	14.13%	6.41%
Nicor Inc.	5.58%	0.95%	4.04%	7.80%	7.72%	8.82%
Northwest Nat. Gas	7.47%	5.84%	10.23%	15.20%	13.60%	15.22%
Piedmont Natural Gas	12.45%	8.03%	10.36%	15.31%	12.42%	12.84%
South Jersey Inds.	12.30%	11.20%	15.83%	20.08%	18.00%	21.36%
Southwest Gas	9.99%	5.18%	2.48%	9.86%	11.56%	11.60%
WGL Holdings Inc.	7.39%	4.11%	7.07%	8.77%	6.66%	9.29%
Average	9.25%	6.97%	10.14%	14.66%	12.82%	13.63%
Weighted Average	8.61%	6.62%	9.34%	14.23%	11.93%	12.81%
				Across Years,	**Average:***	11.25%
					Weighted:*	10.59%

COST OF EQUITY SAMPLE: MID-SIZED GAS DISTRIBUTION COMPANIES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2001 - 2005	2002 - 2006	2003 - 2007
Atmos Energy	4.49%	2.00%	5.25%	12.89%	8.66%	12.09%
EnergySouth Inc	12.79%	9.55%	17.65%	21.48%	20.77%	23.94%
Laclede Group	6.74%	6.40%	10.56%	14.34%	11.98%	11.89%
New Jersey Resources	13.86%	11.51%	13.47%	15.20%	14.13%	6.41%
Northwest Nat. Gas	7.47%	5.84%	10.23%	15.20%	13.60%	15.22%
Piedmont Natural Gas	12.45%	8.03%	10.36%	15.31%	12.42%	12.84%
Southwest Gas	9.99%	5.18%	2.48%	9.86%	11.56%	11.60%
WGL Holdings Inc.	7.39%	4.11%	7.07%	8.77%	6.66%	9.29%
Average	9.40%	6.58%	9.63%	14.13%	12.47%	12.91%
Weighted Average	8.79%	5.80%	8.26%	13.21%	11.15%	11.74%
				Across Years,	**Average:***	10.85%
					Weighted:*	9.82%

*** Unadjusted for Issuance Costs**

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EXHIBIT DC-RC 15, Page 3 of 3

FLORIDA PUBLIC UTILITIES COMPANY

CUMULATIVE RETURNS: MID-SIZED GAS DISTRIBUTION UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
AGL Resources	8.07%	9.86%	11.07%	12.58%	11.98%	12.15%
Atmos Energy	2.98%	4.09%	5.51%	6.67%	6.20%	7.37%
EnergySouth Inc	11.76%	11.97%	14.79%	15.03%	14.87%	17.42%
Laclede Group	6.32%	7.01%	8.93%	9.38%	9.34%	9.02%
New Jersey Resources	13.73%	13.52%	14.50%	14.89%	13.71%	9.31%
Nicor Inc.	5.24%	3.13%	4.27%	5.73%	6.67%	6.85%
Northwest Nat. Gas	6.94%	6.46%	7.87%	9.29%	9.10%	10.85%
Piedmont Natural Gas	11.56%	11.43%	12.40%	12.91%	12.38%	12.16%
South Jersey Inds.	12.14%	12.75%	14.65%	16.64%	15.42%	16.48%
Southwest Gas	8.23%	6.38%	7.32%	7.94%	9.76%	9.72%
WGL Holdings Inc.	7.18%	6.28%	7.51%	8.53%	7.56%	8.12%
Average	8.56%	8.44%	9.89%	10.87%	10.64%	10.86%
Weighted Average	7.87%	7.88%	9.17%	10.26%	10.01%	10.14%
				Across Years,	**Average:***	9.88%
					Weighted:*	9.22%

COST OF EQUITY SAMPLE: MID-SIZED GAS DISTRIBUTION COMPANIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007	
Atmos Energy	2.98%	4.09%	5.51%	6.67%	6.20%	7.37%	
EnergySouth Inc	11.76%	11.97%	14.79%	15.03%	14.87%	17.42%	
Laclede Group	6.32%	7.01%	8.93%	9.38%	9.34%	9.02%	
New Jersey Resources	13.73%	13.52%	14.50%	14.89%	13.71%	9.31%	
Northwest Nat. Gas	6.94%	6.46%	7.87%	9.29%	9.10%	10.85%	
Piedmont Natural Gas	11.56%	11.43%	12.40%	12.91%	12.38%	12.16%	
Southwest Gas	8.23%	6.38%	7.32%	7.94%	9.76%	9.72%	
WGL Holdings Inc.	7.18%	6.28%	7.51%	8.53%	7.56%	8.12%	
Average	8.59%	8.39%	9.85%	10.58%	10.37%	10.50%	
Weighted Average	7.90%	7.75%	9.03%	9.85%	9.57%	9.60%	
				Across Years,	**Average:***	9.71%	**Realized Historical Returns; Average for Measurement Metrics**
					Weighted:*	8.95%	
							w/o Issuance Costs 9.48%

*** Unadjusted for Issuance Costs**

EXHIBIT DC-RC 16, Page 1 of 3

FLORIDA PUBLIC UTILITIES COMPANY

AVERAGE RETURNS PER ANNUM: MID-SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
Black Hills	15.69%	13.86%	12.71%	14.44%	12.75%	13.42%
Hawaiian Elec.	11.23%	10.19%	12.46%	11.78%	11.14%	9.34%
PNM Resources	11.48%	10.93%	13.78%	15.79%	14.26%	13.28%
Cleco Corp.	12.41%	8.45%	10.41%	11.93%	12.21%	12.35%
Empire Dist. Elec.	8.32%	9.05%	9.29%	9.59%	9.11%	9.31%
MGE Energy	12.59%	13.21%	12.83%	13.08%	11.29%	11.00%
OGE Energy	4.65%	5.21%	8.65%	9.33%	11.33%	11.44%
Otter Tail Corp.	16.90%	13.65%	11.84%	11.58%	11.53%	12.33%
Cen. Vermont Pub. Serv.	16.04%	16.66%	15.88%	13.62%	13.02%	17.48%
CH Energy Group	13.70%	10.72%	10.74%	10.03%	10.03%	9.10%
Energy East Corp.	19.66%	17.09%	17.80%	16.92%	14.83%	14.43%
Florida Public Utilities	17.71%	17.34%	17.85%	17.59%	16.00%	13.72%
NSTAR	14.65%	13.64%	13.85%	14.53%	14.41%	14.60%
SCANA Corp.	9.47%	8.96%	9.39%	10.39%	10.97%	11.67%
UIL Holdings	15.32%	10.58%	14.28%	13.93%	14.62%	13.51%
UNITIL Corp.	10.67%	8.74%	9.44%	8.85%	7.61%	8.65%
G't Plains Energy	1.78%	6.49%	8.08%	7.52%	7.00%	7.06%
DPL Inc.	11.08%	6.08%	10.13%	12.96%	12.40%	12.23%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.95%	9.62%
Pinnacle West Capital	7.61%	6.52%	8.60%	8.83%	8.45%	8.27%
Average	12.21%	10.84%	11.92%	12.19%	11.65%	11.64%
Weighted Average	11.24%	9.93%	11.39%	11.96%	11.58%	11.51%
				Across Years,	**Average:***	11.74%
					Weighted:*	11.27%

COST OF EQUITY SAMPLE: MID SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
Hawaiian Elec.	11.23%	10.19%	12.46%	11.78%	11.14%	9.34%
Empire Dist. Elec.	8.32%	9.05%	9.29%	9.59%	9.11%	9.31%
OGE Energy	4.65%	5.21%	8.65%	9.33%	11.33%	11.44%
Otter Tail Corp.	16.90%	13.65%	11.84%	11.58%	11.53%	12.33%
CH Energy Group	13.70%	10.72%	10.74%	10.03%	10.03%	9.10%
Energy East Corp.	19.66%	17.09%	17.80%	16.92%	14.83%	14.43%
Florida Public Utilities	17.71%	17.34%	17.85%	17.59%	16.00%	13.72%
SCANA Corp.	9.47%	8.96%	9.39%	10.39%	10.97%	11.67%
UIL Holdings	15.32%	10.58%	14.28%	13.93%	14.62%	13.51%
G't Plains Energy	1.78%	6.49%	8.08%	7.52%	7.00%	7.06%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.95%	9.62%
Average	12.00%	10.79%	11.88%	11.80%	11.50%	11.05%
Weighted Average	10.91%	10.10%	11.38%	11.45%	11.26%	11.13%
				Across Years,	**Average:***	11.50%
					Weighted:*	11.04%

*** Unadjusted for Issuance Costs**

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EXHIBIT DC-RC 16, Page 2 of 3

FLORIDA PUBLIC UTILITIES COMPANY

FIVE YEAR RETURNS: MID-SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2001 - 2005	2002 - 2006	2003 - 2007
Black Hills	15.69%	11.15%	12.05%	13.99%	2.79%	11.16%
Hawaiian Elec.	11.23%	8.99%	15.39%	16.55%	13.28%	7.45%
PNM Resources	11.48%	8.89%	17.73%	21.33%	11.63%	15.09%
Cleco Corp.	12.41%	5.26%	9.02%	8.20%	7.22%	12.29%
Empire Dist. Elec.	8.32%	5.46%	3.58%	5.37%	8.59%	10.29%
MGE Energy	12.59%	12.56%	14.95%	17.77%	11.34%	9.42%
OGE Energy	4.65%	0.91%	8.51%	13.13%	14.98%	18.23%
Otter Tail Corp.	16.90%	12.73%	10.20%	9.76%	5.37%	7.75%
Cen. Vermont Pub. Serv.	16.04%	17.55%	19.53%	19.49%	9.65%	18.92%
CH Energy Group	13.70%	6.79%	9.55%	11.58%	7.91%	4.51%
Energy East Corp.	19.66%	3.92%	4.27%	9.44%	9.36%	9.19%
Florida Public Utilities	17.71%	12.62%	11.62%	16.03%	15.32%	9.73%
NSTAR	14.65%	7.08%	9.09%	11.52%	13.12%	14.56%
SCANA Corp.	9.47%	6.01%	8.21%	6.37%	12.22%	13.87%
UIL Holdings	15.32%	1.20%	8.24%	9.52%	11.29%	11.71%
UNITIL Corp.	10.67%	6.07%	6.58%	4.24%	5.40%	6.63%
G't Plains Energy	1.78%	6.04%	11.42%	10.72%	10.06%	12.34%
DPL Inc.	11.08%	3.32%	9.49%	8.28%	7.45%	13.37%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.33%	8.19%
Pinnacle West Capital	7.61%	0.49%	6.60%	7.93%	4.83%	8.94%
Average	12.21%	7.32%	10.32%	11.62%	9.56%	11.18%
Weighted Average	11.24%	5.59%	9.39%	10.77%	9.81%	11.89%
				Across Years,	**Average:***	10.37%
					Weighted:*	9.78%

COST OF EQUITY SAMPLE: MID SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2001 - 2005	2002 - 2006	2003 - 2007
Hawaiian Elec.	11.23%	8.99%	15.39%	16.55%	13.28%	7.45%
Empire Dist. Elec.	8.32%	5.46%	3.58%	5.37%	8.59%	10.29%
OGE Energy	4.65%	0.91%	8.51%	13.13%	14.98%	18.23%
Otter Tail Corp.	16.90%	12.73%	10.20%	9.76%	5.37%	7.75%
CH Energy Group	13.70%	6.79%	9.55%	11.58%	7.91%	4.51%
Energy East Corp.	19.66%	3.92%	4.27%	9.44%	9.36%	9.19%
Florida Public Utilities	17.71%	12.62%	11.62%	16.03%	15.32%	9.73%
SCANA Corp.	9.47%	6.01%	8.21%	6.37%	12.22%	13.87%
UIL Holdings	15.32%	1.20%	8.24%	9.52%	11.29%	11.71%
G't Plains Energy	1.78%	6.04%	11.42%	10.72%	10.06%	12.34%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.33%	8.19%
Average	12.00%	6.73%	9.21%	10.87%	10.70%	10.30%
Weighted Average	10.91%	5.61%	8.74%	10.24%	11.07%	11.57%
				Across Years,	**Average:***	9.97%
					Weighted:*	9.69%

*** Unadjusted for Issuance Costs**

EXHIBIT DC-RC 16, Page 3 of 3

FLORIDA PUBLIC UTILITIES COMPANY

CUMULATIVE RETURNS: MID-SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
Black Hills	12.69%	11.32%	10.52%	12.40%	10.86%	11.69%
Hawaiian Elec.	10.62%	9.65%	11.86%	11.25%	10.65%	8.76%
PNM Resources	9.04%	8.90%	11.80%	13.91%	12.52%	11.70%
Cleco Corp.	11.40%	7.24%	9.25%	10.84%	11.24%	11.47%
Empire Dist. Elec.	7.47%	8.32%	8.67%	9.03%	8.61%	8.85%
MGE Energy	12.01%	12.71%	12.41%	12.71%	10.83%	10.59%
OGE Energy	3.63%	4.35%	7.59%	8.38%	10.34%	10.55%
Otter Tail Corp.	16.59%	13.14%	11.32%	11.12%	11.13%	11.93%
Cen. Vermont Pub. Serv.	14.30%	15.20%	14.62%	12.36%	11.90%	15.80%
CH Energy Group	12.67%	9.67%	9.84%	9.23%	9.32%	8.43%
Energy East Corp.	15.50%	13.54%	14.72%	14.21%	12.31%	12.15%
Florida Public Utilities	16.57%	16.39%	17.03%	16.87%	15.27%	12.85%
NSTAR	13.66%	12.80%	13.13%	13.89%	13.84%	14.08%
SCANA Corp.	8.42%	8.08%	8.63%	9.69%	10.33%	11.07%
UIL Holdings	13.61%	8.64%	12.24%	12.15%	13.01%	12.02%
UNITIL Corp.	10.17%	8.24%	9.00%	8.46%	7.20%	8.24%
G't Plains Energy	1.53%	5.81%	7.41%	6.93%	6.47%	6.58%
DPL Inc.	9.38%	4.05%	7.93%	10.76%	10.45%	10.47%
Vectren Corp.	5.09%	4.52%	5.70%	6.74%	6.45%	6.57%
Pinnacle West Capital	5.99%	5.16%	7.29%	7.68%	7.43%	7.35%
Average	10.52%	9.39%	10.55%	10.93%	10.51%	10.56%
Weighted Average	9.33%	8.31%	9.85%	10.55%	10.31%	10.35%
				Across Years,	**Average:***	10.41%
					Weighted:*	9.78%

COST OF EQUITY SAMPLE: MID SIZED ELECTRIC UTILITIES

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006	1998 - 2007
Hawaiian Elec.	10.62%	9.65%	11.86%	11.25%	10.65%	8.76%
Empire Dist. Elec.	7.47%	8.32%	8.67%	9.03%	8.61%	8.85%
OGE Energy	3.63%	4.35%	7.59%	8.38%	10.34%	10.55%
Otter Tail Corp.	16.59%	13.14%	11.32%	11.12%	11.13%	11.93%
CH Energy Group	12.67%	9.67%	9.84%	9.23%	9.32%	8.43%
Energy East Corp.	15.50%	13.54%	14.72%	14.21%	12.31%	12.15%
Florida Public Utilities	16.57%	16.39%	17.03%	16.87%	15.27%	12.85%
SCANA Corp.	8.42%	8.08%	8.63%	9.69%	10.33%	11.07%
UIL Holdings	13.61%	8.64%	12.24%	12.15%	13.01%	12.02%
G't Plains Energy	1.53%	5.81%	7.41%	6.93%	6.47%	6.58%
Vectren Corp.	5.09%	4.52%	5.70%	6.74%	6.45%	6.57%
Average	10.15%	9.28%	10.46%	10.51%	10.35%	9.98%
Weighted Average	8.77%	8.39%	9.78%	10.00%	9.96%	9.95%
				Across Years,	**Average:***	10.12%
					Weighted:*	9.47%

Realized Historical Returns; Average for Measurement Metrics	
w/o Issuance Costs	10.07%
with Issuance Costs	10.40%

*** Unadjusted for Issuance Costs**

EXHIBIT DC-RC 17

SELECTION SCREEN 1: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

Company	Ticker	'07 Market Cap ($M)	2007 Year End Beta	Average Beta 2003-2006	Standard Deviation, Beta 2003-2007	2007 Stock Price	2007 Financial Results: Revenues (M$)	Operating Margins (M$)	Total Assets (M$)	Assets/ Revenue
AGL Resources	ATG	3,058	0.85	0.84	0.09	40.03	2,494	27.02	6,268	2.51
Atmos Energy	ATO	2,750	0.80	0.69	0.05	30.78	5,898	13.34	5,897	1.00
EnergySouth Inc	ENSI	343	0.65	0.54	0.05	42.89	135	38.66	372	2.76
Laclede Group	LG	709	0.90	0.74	0.09	32.77	2,022	6.89	1,641	0.81
New Jersey Resources	NJR	1,397	0.80	0.73	0.06	33.58	3,022	5.41	2,231	0.74
Nicor Inc.	GAS	2,055	1.05	1.06	0.11	44.78	3,176	16.97	4,252	1.34
Northwest Nat. Gas	NWN	1,220	0.80	0.68	0.06	46.20	1,033	21.61	2,014	1.95
Piedmont Natural Gas	PNY	1,914	0.80	0.75	0.04	26.14	1,711	16.20	2,820	1.65
South Jersey Inds.	SJI	1,063	0.70	0.59	0.09	35.91	956	16.99	1,529	1.60
Southwest Gas	SWX	1,441	0.85	0.78	0.06	33.66	2,152	18.73	3,670	1.71
WGL Holdings Inc.	WGL	1,613	0.85	0.75	0.07	32.61	2,646	11.84	3,046	1.15
Average		1,597	0.82	0.74	0.07	36.30	2,295	17.61	3,067	1.56
Standard Deviation			0.10	0.14						0.66

EXHIBIT DC-RC 18

SELECTION SCREEN 1: MID-SIZED ELECTRIC UTILITIES

Company	Ticker	'07 Market Cap ($M)	2007 Year End Beta	Average Beta 2003-2006	Standard Deviation, Beta 2003-2007	2007 Stock Price	2007 Financial Results: Revenues (M$)	Operating Margins (M$)	Total Assets (M$)	Assets/ Revenue
Black Hills	BKH	1,522	1.10	0.94	0.11	40.26	696	40.13	2,473	3.55
Hawaiian Elec.	HE	1,998	0.70	0.65	0.07	23.95	2,536	14.80	10,294	4.06
PNM Resources	PNM	2,081	0.95	0.86	0.12	27.09	1,914	14.81	5,872	3.07
Cleco Corp.	CNL	1,549	1.35	1.09	0.15	25.85	1,031	17.43	2,711	2.63
Empire Dist. Elec.	EDE	795	0.85	0.69	0.09	23.66	490	28.01	1,472	3.00
MGE Energy	MGEE	748	0.85	0.64	0.09	34.06	538	21.55	1,112	2.07
OGE Energy	OGE	3,332	0.75	0.70	0.07	36.30	3,798	17.13	5,238	1.38
Otter Tail Corp.	OTTR	1,011	0.75	0.58	0.05	33.86	1,239	12.40	1,455	1.17
Cen. Vermont Pub. Serv.	CV	326	0.85	0.54	0.11	31.81	329	11.69	540	1.64
CH Energy Group	CHG	743	0.85	0.79	0.06	47.14	1,197	9.63	1,495	1.25
Energy East Corp.	EAS	4,067	0.85	0.80	0.08	25.70	5,178	19.35	11,879	2.29
Florida Public Utilities	FPU	74	0.55	0.60	0.06	12.23	137	14.75	192	1.41
NSTAR	NST	3,672	0.75	0.71	0.06	34.38	3,262	27.16	7,760	2.38
SCANA Corp.	SCG	4,795	0.80	0.71	0.09	40.98	4,621	21.25	10,165	2.20
UIL Holdings	UIL	859	0.90	0.79	0.10	34.33	982	17.89	1,776	1.81
UNITIL Corp.	UTL	160	0.45	0.41	0.03	27.93	263	19.02	475	1.81
G't Plains Energy	GXP	2,608	0.85	0.81	0.09	30.24	3,267	16.15	4,827	1.48
DPL Inc.	DPL	3,290	0.90	0.90	0.07	28.97	1,516	33.31	3,567	2.35
Vectren Corp.	VVC	2,143	0.90	0.79	0.05	28.06	2,282	19.33	4,296	1.88
Pinnacle West Capital	PNW	4,441	1.00	0.86	0.12	44.20	3,524	28.17	11,244	3.19
Average		2,011	0.85	0.74	0.08		1,940	20.20	4,442	2.23
Standard Deviation			0.19	0.15						0.81

EXHIBIT DC-RC 19

SELECTION SCREEN 2: MODERATE-SIZED GAS DISTRIBUTION UTILITIES

		Equity Participation in Total Capital					Measures of Market Risk				Measures of Business and Financial Risk			
											Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share
Company	Ticker	1998	2002	2005	2007	Average	2007 Beta	Average Beta, 2003 - 2006	S.D., CAPM Beta	Annual Variation In Market Return (%)	5 Year	5 Year	10 Year	10 Year
AGL Resources	ATG	50%	42%	48%	50%	47%	0.85	0.84	0.09	8.08	0.28	0.11	0.63	0.33
Atmos Energy	ATO	48%	46%	42%	48%	46%	0.80	0.69	0.05	3.44	0.17	0.10	0.38	0.25
EnergySouth Inc	ENSI	50%	44%	57%	50%	50%	0.65	0.54	0.05	9.64	0.20	0.12	0.32	0.22
Laclede Group	LG	59%	52%	52%	55%	54%	0.90	0.74	0.09	4.31	0.27	0.13	0.38	0.22
New Jersey Resources	NJR	47%	49%	58%	63%	54%	0.80	0.73	0.06	6.35	0.13	0.08	0.29	0.20
Nicor Inc.	GAS	57%	65%	63%	69%	63%	1.05	1.06	0.11	3.60	0.41	0.16	0.36	0.14
Northwest Nat. Gas	NWN	51%	52%	53%	54%	52%	0.80	0.68	0.06	7.38	0.40	0.19	0.46	0.24
Piedmont Natural Gas	PNY	55%	56%	59%	52%	55%	0.80	0.75	0.04	4.08	0.11	0.08	0.18	0.16
South Jersey Inds.	SJI	33%	46%	55%	57%	48%	0.70	0.59	0.09	7.92	0.43	0.24	0.54	0.38
Southwest Gas	SWX	35%	34%	36%	42%	37%	0.85	0.78	0.06	4.60	0.39	0.25	0.34	0.23
WGL Holdings Inc.	WGL	57%	52%	59%	60%	57%	0.85	0.75	0.07	2.54	0.14	0.07	0.35	0.19
Average		49%	49%	53%	54%	51%	0.82	0.74	0.07	5.63	0.27	0.14	0.39	0.23
Standard Deviation						7%	0.10	0.14	0.02	2.34	0.12	0.06	0.12	0.07

EXHIBIT DC-RC 20

SELECTION CREEN 2: MID-SIZED ELECTRIC UTILITIES

		Equity Participation in Total Capital					Measures of Market Risk				Measures of Business and Financial Risk			
											Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share
Company	Ticker	1998	2002	2005	2007	Average	2007 Beta	Average Beta, 2003 - 2006	S.D., CAPM Beta	Annual Variation In Market Return (%)	5 Year	5 Year	10 Year	10 Year
Black Hills	BKH	56%	46%	52%	63%	54%	1.10	0.94	0.11	6.17	0.37	0.17	0.55	0.25
Hawaiian Elec.	HE	43%	46%	53%	51%	48%	0.70	0.65	0.07	3.86	0.17	0.13	0.16	0.11
PNM Resources	PNM	45%	50%	42%	58%	49%	0.95	0.86	0.12	5.85	0.38	0.29	0.49	0.34
Cleco Corp.	CNL	52%	38%	52%	57%	50%	1.35	1.09	0.15	3.48	0.06	0.04	0.13	0.10
Empire Dist. Elec.	EDE	45%	44%	49%	50%	47%	0.85	0.69	0.09	1.76	0.24	0.21	0.28	0.25
MGE Energy	MGEE	53%	54%	61%	65%	58%	0.85	0.64	0.09	5.77	0.28	0.15	0.26	0.15
OGE Energy	OGE	53%	40%	50%	56%	50%	0.75	0.70	0.07	5.61	0.43	0.20	0.41	0.22
Otter Tail Corp.	OTTR	51%	53%	63%	59%	57%	0.75	0.58	0.05	4.64	0.14	0.08	0.17	0.10
Cen. Vermont Pub. Serv.	CV	58%	54%	62%	61%	59%	0.85	0.54	0.11	6.03	0.63	0.53	0.55	0.50
CH Energy Group	CHG	53%	62%	58%	55%	57%	0.85	0.79	0.06	4.44	0.10	0.04	0.28	0.10
Energy East Corp.	EAS	53%	39%	44%	45%	45%	0.85	0.80	0.08	2.40	0.13	0.08	0.22	0.13
Florida Public Utilities	FPU	53%	37%	47%	49%	47%	0.55	0.60	0.06	2.44	0.11	0.19	0.09	0.16
NSTAR	NST	50%	38%	39%	40%	42%	0.75	0.71	0.06	5.07	0.14	0.07	0.22	0.13
SCANA Corp.	SCG	49%	42%	47%	50%	47%	0.80	0.71	0.09	6.08	0.11	0.04	0.41	0.17
UIL Holdings	UIL	38%	55%	53%	49%	49%	0.90	0.79	0.10	3.52	0.30	0.19	0.46	0.24
UNITIL Corp.	UTL	48%	40%	43%	38%	42%	0.45	0.41	0.03	1.43	0.07	0.04	0.15	0.10
G't Plains Energy	GXP	47%	45%	51%	58%	50%	0.85	0.81	0.09	2.90	0.34	0.16	0.36	0.19
DPL Inc.	DPL	56%	25%	38%	36%	39%	0.90	0.90	0.07	4.48	0.43	0.32	0.38	0.29
Vectren Corp.	VVC	N/A	48%	49%	50%	50%	0.90	0.79	0.05	2.81	0.20	0.12	0.26	0.17
Pinnacle West Capital	PNW	50%	48%	57%	53%	52%	1.00	0.86	0.12	3.47	0.37	0.14	0.45	0.15
Average		50%	45%	50%	52%	50%	0.85	0.74	8%	4.14	0.25	0.16	0.31	0.19
Standard Deviation						5%	0.19	0.15	0.03	1.52	0.15	0.12	0.14	0.10

EXHIBIT DC-RC 21

FLORIDA PUBLIC UTILITIES COMPANY

HISTORICAL YEAR-END CAPITAL STRUCTURE

Capital Component	2003 Amount ($000's)	2003 Share (%)	2004 Amount ($000's)	2004 Share (%)	2005 Amount ($000's)	2005 Share (%)	2006 Amount ($000's)	2006 Share (%)	2007 Amount ($000's)	2007 Share (%)
Common Equity	41,463	43.7%	43,213	43.1%	45,503	42.8%	47,573	46.5%	48,946	44.5%
Preferred Stock	600	0.6%	600	0.6%	600	0.6%	600	0.6%	600	0.5%
Long Term Debt	50,454	53.2%	50,538	50.5%	50,620	47.6%	50,702	49.5%	49,363	44.9%
Short Term Debt	2,278	2.4%	5,825	5.8%	9,558	9.0%	3,466	3.4%	11,122	10.1%
Total Capitalization	94,795	100.0%	100,176	100.0%	106,281	100.0%	102,341	100.0%	110,031	100.0%

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EXHIBIT DC-RC 22

FLORIDA PUBLIC UTILITIES COMPANY

FINANCIAL RESULTS OVER RECENT YEARS

	2003	2004	2005	2006	2007
Pre-tax Interest Coverage Ratio (x)	1.71	2.01	2.33	2.21	1.81
Earned Returns on Average Book Equity (%)	6.9%	8.4%	9.5%	8.9%	6.8%
Book Value/Share ($)	$7.08	$7.31	$7.64	$7.94	$8.10
Dividends/Share ($)	$0.39	$0.40	$0.41	$0.42	$0.44
Earnings/Share ($)	$0.43	$0.60	$0.71	$0.69	$0.54
Market Value/Share ($)	$10.53	$12.77	$13.65	$13.25	$11.75
Market/Book Ratio (%)	148.7%	174.7%	178.7%	166.9%	145.1%
Price/Earning Ratio (6) / (5)	24.49	21.28	19.23	19.20	21.76

* Excluding the Sale of Water Division

** Common Share information re-stated to reflect three for two stock split on July 25, 2005

EXHIBIT DC-RC 23

FLORIDA PUBLIC UTILITIES COMPANY

HISTORICAL INTEREST COVERAGE

Item	2003* ($000's)	2004 ($000's)	2005 ($000's)	2006 ($000's)	2007 ($000's)	Average
Operating Income After Tax	6,638	7,448	8,459	8,191	7,413	
Income Taxes	1,055	1,538	2,178	1,986	1,408	
Operating Income Before Taxes	7,693	8,986	10,637	10,177	8,821	
Interest Charges	4,488	4,462	4,568	4,608	4,870	
Before-Tax Interest Coverage	1.71	2.01	2.33	2.21	1.81	2.02
After-tax Interest Coverage	1.48	1.67	1.85	1.78	1.52	1.66

* Excludes the Inpact of the Sale of the Water Division

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080366-GU

MINIMUM FILING REQUIREMENTS
SCHEDULE A – EXECUTIVE SUMMARY SCHEDULES

December 2008

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU
MINIMUM FILING REQUIREMENTS

INDEX: A SCHEDULES

EXECUTIVE SUMMARY

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING THE MAGNITUDE OF CHANGE - PRESENT VS. PRIOR RATE CASE

TYPE OF DATA SHOWN:
TEST YEAR LAST CASE 2005
TEST YEAR CURRENT CASE 2009
WITNESS: MARTIN

LAST RATE CASE: DOCKET NO. 040216-GU
ORDER NO. PSC-04-1110-PAA-GU

LINE NO.	ITEM	REQUESTED (1)* Historical	(2)* Attrition	(3)* Total	(4)* Projected Test Year 12/31/05	AUTHORIZED (5)* Historical	(6)* Attrition	(7)* Total	(8)* Projected Test Year 12/31/05	CURRENT RATE CASE REQUESTED (9) Projected Test Year 12/31/09	(10)** Dollar or Percent Difference	(11)** Percentage Change
1	Docket Number				040216-GU				040216-GU	080366-GU		
2	Historical Data or Test Year											
3	Projected Test Year				12/31/05				12/31/05			
4	Rate Increase - Permanent				8,186,989				5,865,903	9,917,690	4,051,787	69.07%
5	Rate Increase - Interim				1,490,980				1,236,108	984,054	(252,054)	-20.39%
6	Jurisdictional Rate Base Before Rate Relief				65,835,210				59,171,674	73,747,220	14,575,546	24.63%
7	Jurisdictional Net Operating Income Before Rate Relief				641,221				880,787	335,922	(544,865)	-61.86%
8	Rate of Return Before Rate Relief				0.97%				1.49%	0.46%		
9	System Capitalization				65,835,210				59,171,674	73,747,220	14,575,546	24.63%
10	Overall Rate of Return				8.66%				7.62%	8.74%	1.12%	14.70%
11	Cost of Long-Term Debt				8.04%				8.04%	7.90%	-0.14%	-1.74%
12	Cost of Preferred Stock				4.75%				4.75%	4.75%	0.00%	0.00%
13	Cost of Short-Term Debt				5.98%				4.03%	4.71%	0.68%	16.77%
14	Cost of Customer Deposits				6.28%				6.28%	6.13%	-0.15%	-2.43%
15	Cost of Common Equity				11.50%				11.25%	11.75%	0.50%	4.44%
16	Number of Customers - Average				49,208				49,208	52,137		
17	Date New Permanent Rates Effective								11/18/2004			

(A) As determined by the "File and Suspend" provisions of Section 366.06 (4), Florida Statutes.

* If Company's Last Rate Case Included a Historic and Attrition Year, Complete Columns (1) - (3) and Columns (5) - (7) under the heading "Last Rate Case". If the Company's Last Rate Case was based on a Projected Test Year, Complete Columns (4) AND (8) under the heading "Last Rate Case".

** If the Company's Last Rate Case Included a Historic and Attrition Year, this calculation will be the difference between Column (9) and Column (7). If the Company's Last Rate Case was based on a Projected Test Year, this calculation will be the difference between Column (9) and Column (8).

SUPPORTING SCHEDULES: F-7, G-1 p.1, G-2 p.1, G-3 p.1, G-6

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING AN ANALYSIS OF PERMANENT RATE INCREASE REQUESTED.

TYPE OF DATA SHOWN:
HISTORIC YEAR LAST CASE 2003
TEST YEAR LAST CASE 2005
TEST YEAR CURRENT CASE 2009
WITNESS: MARTIN

Line No.	Description	INCREASE IN GROSS REVENUE DOLLARS	INCREMENTAL AMOUNT OVER PREVIOUS ITEM	PERCENT OF TOTAL INCREASE
1	REVENUE AMOUNT REQUESTED TO RESTORE ADJUSTED NET OPERATING INCOME TO PREVIOUSLY ALLOWED OVERALL RATE OF RETURN OF 7.62% ON PREVIOUSLY AUTHORIZED 2005 RATE BASE			
	2005 AUTHORIZED RATE BASE	59,171,674		
	PREVIOUSLY ALLOWED RATE OF RETURN	7.62%		
	N.O.I. REQUIREMENTS @ PREVIOUSLY ALLOWED RATE OF RETURN	4,508,882		
	2009 PROJECTED N.O.I.	335,922		
	N.O.I. DEFICIENCY	4,172,960		
	EXPANSION FACTOR	1.6233		
	REVENUE DEFICIENCY	6,773,966	6,773,966	68.3%
2	REVENUE AMOUNT REQUESTED TO ALLOW UTILITY TO EARN 2009 REQUESTED RATE OF RETURN ON PREVIOUSLY AUTHORIZED 2005 RATE BASE			
	2005 AUTHORIZED RATE BASE	59,171,674		
	REQUESTED RATE OF RETURN	8.74%		
	N.O.I. REQUIREMENTS @ REQUESTED RATE OF RETURN	5,171,604		
	2009 PROJECTED N.O.I.	335,922		
	N.O.I. DEFICIENCY	4,835,682		
	EXPANSION FACTOR	1.6233		
	REVENUE DEFICIENCY	7,849,763	1,075,798	10.8%
3	EFFECT OF PROJECTED TEST YEAR: REVENUE AMOUNT REQUESTED TO ALLOW UTILITY TO EARN A REQUESTED RATE OF RETURN OF 8.74% ON 2009 RATE BASE			
	2009 ADJUSTED RATE BASE	73,747,220		
	REQUESTED RATE OF RETURN	8.74%		
	N.O.I. REQUIREMENTS @ REQUESTED RATE OF RETURN	6,445,507		
	LESS: ADJUSTED 2009 N.O.I.	335,922		
	N.O.I. DEFICIENCY	6,109,585		
	EXPANSION FACTOR	1.6233		
	INCREASE IN REVENUE TO ALLOWED REQUESTED RATE OF RETURN OF 8.74%	9,917,690	2,067,927	20.9%
	PROJECTED 2009 TEST YEAR BASE REVENUE AT CURRENT RATES	22,225,975		
5	TOTAL PERMANENT RATE INCREASE OVER CURRENT BASE RATES	44.62%	9,917,690	100%

SUPPORTING SCHEDULES: D-1 p.1, G-3 p.1, G-6

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING AN ANALYSIS OF JURISDICTIONAL RATE BASE.

TYPE OF DATA SHOWN:
HISTORIC YEAR LAST CASE 2003
TEST YEAR LAST CASE 2005
TEST YEAR CURRENT CASE 2009
WITNESS: MARTIN

		Rate Base Determined by Commission in Last Rate Case				Rate Base Requested by Company in Current Rate Case		
Line No.	Item	(1)* Historic	(2)* Attrition	(3)* Projected Test Year 12/31/05	(4)* Projected Test Year 12/31/05	(5) Projected Test Year 12/31/09	(6)** Dollar Difference	(7)** Percent Difference
	<u>Utility Plant</u>			<u>Requested</u>	<u>Ordered</u>			
1	Plant In Service			89,939,143	86,086,339	112,805,057	26,718,718	31%
2	(Common Plant)			3,429,181	3,429,181	3,494,938	65,757	2%
3	Construction Work In Progress			194,004	235,540	359,427	123,887	53%
4	Utility Plant Acquisition Adjustment			3,603,400	1,263,776	1,263,776	-	0%
5	Gross Utility Plant			97,165,728	91,014,836	117,923,198	26,908,362	30%
	<u>Deductions</u>							
6	Accumulated Depreciation			28,935,572	28,663,344	(35,836,083)	(64,499,427)	-225%
7	(Common Plant)			1,039,014	1,039,014	(1,269,018)	(2,308,032)	-222%
8	Accumulated Amortization			-	-	-	-	
9	Limited Term Utility Plant			-	-	-	-	
10	Acquisition Adjustment			358,128	436,317	(544,545)	(980,862)	-225%
11	Customer Advances for Construction			997,805	997,805	(1,659,376)	(2,657,181)	-266%
12	Total Deductions			31,330,519	31,136,480	(39,309,022)	(70,445,502)	-226%
13	Net Utility Plant			65,835,209	59,878,356	78,614,176	18,735,820	31%
14	Allowance for Working Capital			-	(706,682)	(4,866,956)	(4,160,274)	589%
15	Rate Base			65,835,209	59,171,674	73,747,220	14,575,546	25%

* If the Company's Last Rate Case included a Historic and Attrition Year, Complete Columns (1) - (3).
If the Company's Last Rate Case was based on a Projected Test Year, Complete Column (4).

** If the Company's Last Rate Case included a Historic and Attrition Year, this calculation will be the difference between Column (5) and Column (3). If the Company's Last Rate Case was based on a Projected Test Year, this calculation will be the difference between Column (5) and Column (4).

SUPPORTING SCHEDULES: G-1 p.1

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING AN ANALYSIS OF JURISDICTIONAL NET OPERATING INCOME

TYPE OF DATA SHOWN:
HISTORIC YEAR LAST CASE 2003
TEST YEAR LAST CASE 2005
TEST YEAR CURRENT CASE 2009
WITNESS: MARTIN

		NET OPERATING INCOME AS DETERMINED BY COMMISSION IN LAST RATE CASE				CURRENT CASE		
		(1)*	(2)*	(3)*	(4)*	(5)	(6)**	(7)**
LINE NO.	ITEM	Historic	Attrition	Projected Test Year 12/31/05	Projected Test Year 12/31/05	Projected Test Year 12/31/09	DOLLAR DIFFERENCE	PERCENT DIFFERENCE
				REQUESTED	ORDERED			
1	OPERATING REVENUES (A)			22,568,224	22,571,824	27,918,917	5,347,093	23.7%
	OPERATING REVENUE DEDUCTIONS:							
2	OPERATING & MAINTENANCE EXPENSE			14,795,629	14,178,039	19,003,804	4,825,765	34.0%
3	DEPRECIATION EXPENSE			2,827,875	2,945,890	3,388,490	442,600	15.0%
4	AMORTIZATION EXPENSE			932,654	1,053,711	1,110,518	56,807	5.4%
5	TAXES OTHER THAN INCOME			4,464,720	4,324,539	5,609,864	1,285,325	29.7%
6	INCOME TAXES (FEDERAL & STATE)			(2,450,857)	(2,168,126)	277,413	2,445,539	-112.8%
7	DEFERRED TAXES (FEDERAL & STATE)			1,397,315	1,397,315	(1,772,431)	(3,169,746)	
8	INVESTMENT TAX CREDITS			(40,331)	(40,331)	(34,663)	5,668	-14.1%
9	TOTAL OPERATING REVENUE DEDUCTIONS			21,927,005	21,691,037	27,582,995	5,891,958	27.2%
10	NET OPERATING INCOME (B)			641,219	880,787	335,922	(544,865)	-61.9%

(A) EXCLUDES FUEL REVENUE
(B) BEFORE RATE RELIEF

* IF THE COMPANY'S LAST RATE CASE INCLUDED A HISTORIC AND ATTRITION YEAR, COMPLETE COLUMNS (1) - (3). IF THE COMPANY'S LAST RATE CASE WAS BASED ON A PROJECTED TEST YEAR, COMPLETE COLUMN (4).

** IF THE COMPANY'S LAST RATE CASE INCLUDED A HISTORIC AND ATTRITION YEAR, THIS CALCULATION WILL BE THE DIFFERENCE BETWEEN COLUMN (5) AND COLUMN (3). IF THE COMPANY'S LAST RATE CASE WAS BASED ON A PROJECTED TEST YEAR, THIS CALCULATION WILL BE THE DIFFERENCE BETWEEN COLUMN (5) AND COLUMN (4).

SUPPORTING SCHEDULES: G-2 p.1

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION:PROVIDE A SCHEDULE SHOWING OVERALL RATE OF RETURN COMPARISON

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

TEST YEAR LAST CASE 2005
TEST YEAR CURRENT CASE 2009
WITNESS: COX

LINE NO.	ITEM	DOLLARS	RATIO	EMBEDDED COST	WEIGHTED COST
	LAST RATE CASE (AUTHORIZED)*				
1	Long Term Debt	21,870,836	36.96%	8.04%	2.97%
2	Short-Term Debt	2,484,853	4.20%	4.03%	0.17%
3	Preferred Stock	260,642	0.44%	4.75%	0.02%
4	Common Equity	20,938,759	35.39%	11.25%	3.98%
5	Customer Deposits	4,094,408	6.92%	6.28%	0.43%
6	Deferred Taxes	9,245,613	15.62%	0.00%	0.00%
7	ITC at Zero Cost	-	0.00%	0.00%	0.00%
8	ITC at Overall Cost	276,563	0.47%	9.28%	0.04%
9					
10					
11	TOTAL CAPITALIZATION	59,171,674	100.00%	NA	7.62%
12		===========	===========	===========	===========
13					
14	CURRENT RATE CASE (REQUESTED)				
15					
16					
17	Long Term Debt	25,861,386	35.1%	7.90%	2.77%
18	Short-Term Debt	7,363,771	10.0%	4.71%	0.47%
19	Preferred Stock	320,500	0.4%	4.75%	0.02%
20	Common Equity	31,130,696	42.2%	11.75%	4.96%
21	Customer Deposits	6,181,495	8.4%	6.13%	0.51%
22	Deferred Taxes	2,773,818	3.8%	0.00%	0.00%
23	ITC at Zero Cost	-	0.0%	0.00%	0.00%
24	ITC at Overall Cost	115,553	0.2%	9.38%	0.01%
25					
26					
27	TOTAL CAPITALIZATION	73,747,220	100.00%		8.74%
		===========	===========	===========	===========

* IF THE COMPANY'S LAST RATE CASE INCLUDED A HISTORIC AND ATTRITION YEAR, REPORT THE CAPITAL STRUCTURE FOR THE ATTRITION YEAR. IF THE COMPANY'S LAST RATE CASE WAS BASED ON A PROJECTED TEST YEAR, REPORT THE CAPITAL STRUCTURE FOR THE PROJECTED TEST YEAR.

SUPPORTING SCHEDULES:G-3 p. 1

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SUMMARY OF FINANCIAL INDICATORS AS SPECIFIED BELOW FOR THE HISTORIC DATA BASE YEAR OF THE LAST RATE CASE, HISTORIC DATA BASE YEAR FOR THIS CASE, AND THE YEAR IMMEDIATELY FOLLOWING THE PRESENT HISTORIC DATA BASE YEAR.

TYPE OF DATA SHOWN:
TY OR BASE YR LAST CASE: 12/31/05
HIS. BASE YR DATA CURRENT: 12/31/2007
BASE YR + 1 CURRENT CASE: 12/31/2008
PROJECTED TY CURRENT CASE: 12/31/2009
WITNESS: COX

LINE NO.	INDICATORS		(1) DATA FROM HISTORIC BASE YR OR TY RELATED TO COMPANY'S PRIOR CASE	(2) DATA FROM HISTORIC BASE YEAR RELATED TO COMPANY'S CURRENT CASE	(3) YEAR AFTER CURRENT HISTORIC BASE YEAR WITHOUT ANY RATE INCREASE *	(4) PROJECTED TEST YEAR WITHOUT ANY RATE INCREASE	(5) PROJECTED TEST YEAR INCLUDING REQUESTED RATE INCREASE
			12/31/2005	12/31/2007	12/31/2008	12/31/2009	12/31/2009
	INTEREST COVERAGE RATIOS:						
1	INCLUDING AFUDC IN INCOME BEFORE INTEREST CHARGES		2.43	2.03	2.50		
2	EXCLUDING AFUDC FROM INCOME BEFORE INTEREST CHARGES		2.43	2.03	2.50		
	OTHER FINANCIAL RATIOS:					NOT AVAILABLE ON CONSOLIDATED BASIS	
3	AFUDC AS A PERCENT OF INCOME AVAILABLE FOR COMMON		65%	73%	N/A	UNTIL JANUARY 2009 WHEN 2009 BUDGET WILL BE COMPLETED	
4	PERCENT OF CONSTRUCTION FUNDS GENERATED INTERNALLY		65%	73%	N/A		
	PREFERRED DIVIDEND COVERAGE:						
5	INCLUDING AFUDC		146.48	113.83	155.45		
6	EXCLUDING AFUDC		146.48	113.83	155.45		
	RATIO OF EARNINGS TO FIXED CHARGES:						
7	INCLUDING AFUDC		2.43	2.03	2.50		
8	EXCLUDING AFUDC		2.43	2.03	2.50		
	EARNINGS PER SHARE:						
9	INCLUDING AFUDC	**	$ 0.71	$ 0.54	$ 0.66		
10	EXCLUDING AFUDC	**	$ 0.71	$ 0.54	$ 0.66		
11	DIVIDENDS DECLARED PER SHARE	**	$ 0.41	$ 0.45	$ 0.42		

* Budget 2008

** Re-stated for Stock Splits July 2005 3:2

SUPPORTING SCHEDULES: D-11 p.1-3, G-3 p.9-11

RECAP SCHEDULES:

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080366-GU

MINIMUM FILING REQUIREMENTS
SCHEDULE B – RATE BASE SCHEDULES

December 2008

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU
MINIMUM FILING REQUIREMENTS
INDEX: B SCHEDULES

RATE BASE SCHEDULES

SCHEDULE B-1

13-MONTH AVERAGE BALANCE SHEET - 2007

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE BALANCE SHEETS BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN: HISTORIC TEST YEAR - 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) DEC. '06	(6) JAN. '07	(7) FEB. '07	(8) MAR. '07	(9) APR. '07	(10) MAY. '07	(11) JUN. '07	(12) JUL. '07	(13) AUG. '07	(14) SEP. '07	(15) OCT. '07	(16) NOV. '07	(17) DEC. '07	(18) UTILITY 13-MO AVG
1			ASSETS														
2			PLANT														
3	1010		PLANT-IN-SERVICE - GAS	94,683,552	94,990,873	95,534,332	95,837,385	96,026,430	96,476,464	97,051,188	97,650,644	98,043,282	98,635,433	98,994,423	98,945,732	103,667,291	97,425,925
4	1180		PLANT-IN-SERVICE - COMMON	2,765,317	2,765,834	2,766,251	2,830,464	2,856,388	2,930,308	2,955,243	2,944,218	2,950,240	2,955,105	2,943,636	2,933,298	2,948,024	2,888,025
5	1070		CWIP - GAS	869,169	1,118,609	952,775	1,128,713	1,387,342	1,488,814	1,590,690	4,809,048	5,144,796	5,732,360	5,594,136	5,750,836	1,290,848	2,835,241
6	1070		CWIP - COMMON	158,594	176,669	180,534	167,011	147,317	94,085	51,599	62,842	65,511	85,237	110,163	126,374	152,957	121,454
7	1140		ACQUISITION ADJ. (GROSS)	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579	1,816,579
8			GROSS UTILITY PLANT	100,293,211	100,868,564	101,250,472	101,780,152	102,234,056	102,806,250	103,465,299	107,283,331	108,020,407	109,224,714	109,458,938	109,572,819	109,875,699	105,087,224
9			RESERVE														
10	1080		PLANT RESERVE - GAS	(30,762,547)	(31,000,246)	(31,238,425)	(31,403,630)	(31,615,147)	(31,833,526)	(32,024,995)	(32,239,165)	(32,461,504)	(32,616,514)	(32,826,658)	(32,692,424)	(32,994,062)	(31,977,603)
11	1190		PLANT RESERVE - COMMON	(925,570)	(941,367)	(956,459)	(964,914)	(978,136)	(994,937)	(1,009,615)	(1,013,637)	(1,030,513)	(1,045,927)	(1,056,132)	(1,060,950)	(1,077,395)	(1,004,273)
12	1150		ACQUISITION ADJ. - RESERVE	(374,686)	(377,274)	(379,862)	(382,451)	(385,039)	(387,627)	(390,216)	(392,804)	(395,676)	(397,981)	(400,569)	(403,157)	(405,746)	(390,238)
13			TOTAL RESERVES	(32,062,803)	(32,318,887)	(32,574,746)	(32,750,995)	(32,978,322)	(33,216,090)	(33,424,826)	(33,645,606)	(33,887,693)	(34,060,422)	(34,283,359)	(34,156,531)	(34,477,203)	(33,372,114)
14			NET PLANT	68,230,408	68,549,677	68,675,726	69,029,157	69,255,734	69,590,160	70,040,473	73,637,725	74,132,714	75,164,292	75,175,579	75,416,288	75,398,496	71,715,110
15			OTHER PROPERTY AND INVESTMENTS														
16	1210		NON-UTILITY PROPERTY	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436	8,436
17	1280		OTHER FUNDS	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100
18			TOTAL	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536	13,536
19			CURRENT AND ACCRUED ASSETS														
20	1310		CASH	23,800	620,622	675,876	1,038,905	405,089	719,716	652,625	(655,021)	(692,724)	1,651,920	432,705	(679,051)	1,404,456	430,686
21	1350		WORKING FUNDS / PETTY CASH	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,200	25,238	25,238	25,206
22	1350	10	FUNDS-PETTY CASH, ALLOC.	260	260	260	260	260	260	260	260	260	260	260	260	260	260
23	1420		ACCTS REC - CUSTOMERS	5,573,582	5,941,919	6,233,401	6,068,912	5,399,066	3,933,868	3,904,187	3,649,628	3,143,598	3,079,308	3,643,204	3,893,271	4,777,229	4,557,012
24	1430		ACCOUNTS RECEIVABLE - OTHER	4,018	(1,929)	(5,354)	16,842	58,468	21,363	116,014	120,156	123,216	127,590	97,846	(45,552)	72,786	54,266
25	1440		ALLOW. FOR UNCOLLECTABLE	(188,389)	(203,153)	(214,791)	(230,717)	(229,706)	(232,583)	(245,495)	(233,306)	(240,767)	(218,223)	(211,369)	(210,511)	(198,410)	(219,801)
26	1540		MATERIALS & SUPPLIES INV.	511,110	493,291	470,570	487,096	489,428	505,835	493,899	445,543	516,300	523,735	509,691	502,531	505,864	496,530
27	1630		PPD STORES EXPENSE	-	8,527	(341)	-	(159)	(1,212)	-	7,409	1,610	-	(1,607)	(3)	-	1,095
28	1650	2, 5	PPD INSURANCE	374,895	339,012	303,129	277,877	270,697	187,070	118,330	59,970	80,644	492,788	455,652	420,319	381,433	289,370
29	1650	4	PPD MISCELLANEOUS	68,799	66,273	58,956	40,679	62,641	74,114	65,029	55,948	54,974	52,624	73,113	64,291	55,469	60,993
30	1650	41	PPD ORCOM MAINTENANCE	46,640	42,753	38,866	34,979	31,093	34,488	29,873	25,258	20,643	16,029	11,414	6,799	51,156	29,999
31	1730		UNBILLED REVENUES	1,193,529	1,233,328	1,126,203	969,192	889,848	929,229	762,376	685,438	672,217	728,623	782,995	979,823	1,095,084	926,761
32			TOTAL	7,633,444	8,566,103	8,711,975	8,729,225	7,401,925	6,197,347	5,922,298	4,186,483	3,705,171	6,479,854	5,819,104	4,957,415	8,170,564	6,652,377
33			DEFERRED ASSETS														
34	1810	1	UNAMORT DEBT DISCOUNT	882,597	902,689	891,778	900,373	907,533	892,961	886,305	928,185	928,984	991,473	987,794	986,324	1,048,953	933,534
35	1820	2	REG ASSET - RETIREMENT PL	315,331	315,331	315,331	291,282	291,282	291,282	189,188	189,188	189,188	90,099	90,099	90,099	(372,073)	175,817
36	1820	3	REG ASSET - ENVRNMTL PEND	8,270,704	8,232,675	8,194,646	8,107,517	8,069,488	8,031,459	7,955,630	7,917,601	7,879,572	7,812,143	7,774,114	7,736,085	7,652,656	7,971,868
37	1820	3n	REG ASSET - STORM RESERVE	283,326	262,814	242,142	220,474	203,041	188,704	175,157	163,229	152,316	10,297	(2,704)	-	-	146,061
38	1840	1	CLEARING - NG	-	53	(18)	-	721	279	-	-	207	388	1,634	1,613	-	375
39	1840	1	CLEARING - ALLOCATED	-	131	-	-	-	-	38	-	-	-	-	-	-	13
40	1860	1	UNAMORTIZED RATE CASE-NG	177,260	169,874	162,489	155,103	147,717	140,331	132,945	125,559	118,174	110,788	103,402	96,016	88,630	132,945
41	1860	1	DEFERRED DR - NG	63,932	56,210	60,793	93,007	98,350	113,596	193,732	51,718	44,141	50,357	54,764	59,403	17,039	73,619
42	1860	23	DEFERRED DR - PENNY ELIM	-	(5)	(9)	(29)	(27)	(39)	(47)	(64)	(60)	(67)	(71)	(73)	-	(38)
43	1860	4	OTHER DEFERRED DEBITS - AEP	3,952,092	3,920,408	3,930,427	3,889,511	3,864,733	3,862,734	3,852,283	3,848,601	3,873,294	3,901,668	4,252,148	4,246,990	4,264,682	3,973,813
44	1860	21, 61	UNDERREC - PGA & CONSERV	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	1860	3	DEF DR - UNDIST CAPITAL PAYRL	-	19,998	19,766	37,122	40,282	63,488	-	13,562	28,725	32,071	53,334	-	5,509	24,143
46	1860	3n	DEF PIPING & CONVERSION	1,520,645	1,485,583	1,459,176	1,423,506	1,415,893	1,396,035	1,406,731	1,428,344	1,414,467	1,424,610	1,414,495	1,381,294	1,369,395	1,426,167
47	1890	1	UNAMORT LOSS ON REACCQU	100,191	102,472	101,233	102,209	103,022	101,368	100,612	105,366	105,457	112,551	112,133	111,966	119,076	105,973
48	1900		DEFERRED TAXES - DIRECT	3,112,865	3,140,608	3,163,203	3,182,671	3,199,753	3,221,762	3,288,250	3,314,159	3,332,315	3,341,135	3,378,719	3,381,531	3,378,384	3,264,256
49			TOTAL	18,678,943	18,608,841	18,540,957	18,402,745	18,341,788	18,303,959	18,180,824	18,085,448	18,066,779	17,877,512	18,219,861	18,091,248	17,572,250	18,228,546
50			TOTAL ASSETS	94,556,331	95,738,156	95,942,193	96,174,663	95,012,982	94,105,001	94,157,131	95,923,192	95,918,201	99,535,194	99,228,080	98,478,487	101,154,846	96,609,569
52																	

SUPPORTING SCHEDULES: B-4, B-5, B-6a, B-6b, B-8, B-8a, B-9, B-11, B-12, B-13, B-14, B-15, B-17, B-18

RECAP SCHEDULES: B-2

SCHEDULE B-1 | 13-MONTH AVERAGE BALANCE SHEET - 2007

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE BALANCE SHEETS BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) CONSOLIDATED 13-MO AVG	(6) REFERENCE	(7) ALLOCATION BASIS	(8) ALLOC. %		(9) UTILITY 13-MO AVG
1			ASSETS						
2	PLANT								
3	1010		PLANT-IN-SERVICE - GAS	97,425,925	RATE BASE	Direct	100%		97,425,925
4	1180		PLANT-IN-SERVICE - COMMON	5,437,338	RATE BASE	Common Plant; Sch. B-5	Various; B-5		2,888,025
5	1070		CWIP - GAS	2,835,241	RATE BASE	Direct	100%		2,835,241
6	1070		CWIP - COMMON	231,467	RATE BASE	Common Plant; Sch. B-8	Various; B-8		121,454
7	1140		ACQUISITION ADJ. (GROSS)	1,816,579	RATE BASE	Direct	100%		1,816,579
8								GROSS UTILITY PLANT	105,087,224
9	RESERVE			-					
10	1080		PLANT RESERVE - GAS	(31,977,603)	RATE BASE	Direct	100%		(31,977,603)
11	1190		PLANT RESERVE - COMMON	(1,910,203)	RATE BASE	Common Plant; Sch. B-11	Various; B-11		(1,004,273)
12	1150		ACQUISITION ADJ. - RESERVE	(390,238)	RATE BASE	Direct	100%		(390,238)
13								TOTAL RESERVES	(33,372,114)
14								NET PLANT	71,715,110
15	OTHER PROPERTY AND INVESTMENTS			-					
16	1210		NON-UTILITY PROPERTY	8,436	WORKING CAPITAL	Direct	100%		8,436
17	1280		OTHER FUNDS	10,000	WORKING CAPITAL	Adj. Gross Profit	51%		5,100
18								TOTAL	13,536
19	CURRENT AND ACCRUED ASSETS			-					
20	1310		CASH	844,483	WORKING CAPITAL	Adj. Gross Profit	51%		430,686
22	1350		WORKING FUNDS / PETTY CASH	25,206	WORKING CAPITAL	Direct	100%		25,206
23	1350	10	FUNDS-PETTY CASH, ALLOC.	500	WORKING CAPITAL	Payroll	52%		260
24	1420		ACCTS REC - CUSTOMERS	4,557,012	WORKING CAPITAL	Direct	100%		4,557,012
25	1430		ACCOUNTS RECEIVABLE - OTHER	54,266	WORKING CAPITAL	Direct	100%		54,266
26	1440		ALLOW. FOR UNCOLLECTABLE	(219,801)	WORKING CAPITAL	Direct	100%		(219,801)
27	1540		MATERIALS & SUPPLIES INV.	496,530	WORKING CAPITAL	Direct	100%		496,530
28	1630		PPD STORES EXPENSE	1,095	WORKING CAPITAL	Direct	100%		1,095
29	1650	2, 5	PPD INSURANCE	567,393	WORKING CAPITAL	Adj. Gross Profit	51%		289,370
30	1650	4	PPD MISCELLANEOUS	119,594	WORKING CAPITAL	Adj. Gross Profit	51%		60,993
31	1650	41	PPD ORCOM MAINTENANCE	58,822	WORKING CAPITAL	Adj. Gross Profit	51%		29,999
32	1730		UNBILLED REVENUES	926,761	WORKING CAPITAL	Direct	100%		926,761
33								TOTAL	6,652,377
34	DEFERRED ASSETS			-					
35	1810	1	UNAMORT DEBT DISCOUNT	1,758,295	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		933,534
36	1820	2	REG ASSET - RETIREMENT PL	266,390	WORKING CAPITAL	Regulated Payroll	66%		175,817
37	1820	3	REG ASSET - ENVRNMTL PEND	7,971,868	WORKING CAPITAL	Direct	100%		7,971,868
38	1820	3n	REG ASSET - STORM RESERVE	146,061	WORKING CAPITAL	Direct	100%		146,061
39	1840		CLEARING - NG	375	WORKING CAPITAL	Direct	100%		375
40	1840		CLEARING - ALLOCATED	25	WORKING CAPITAL	Adj. Gross Profit	51%		13
41	1860	1	UNAMORTIZED RATE CASE-NG	132,945	WORKING CAPITAL	Direct	100%		132,945
42	1860	1	DEFERRED DR - NG	73,619	WORKING CAPITAL	Direct	100%		73,619
43	1860	23	DEFERRED DR - PENNY ELIM	(74)	WORKING CAPITAL	Adj. Gross Profit	51%		(38)
44	1860	4	OTHER DEFERRED DEBITS - AEP	3,973,813	WORKING CAPITAL	Direct	100%		3,973,813
45	1860	21, 61	UNDERREC - PGA & CONSERV	-	WORKING CAPITAL	Direct	100%		-
46	1860	3	DEF DR - UNDIST CAPITAL PAYRL	24,143	WORKING CAPITAL	Direct	100%		24,143
47	1860	3n	DEF PIPING & CONVERSION	1,426,167	WORKING CAPITAL	Direct	100%		1,426,167
48	1890	1	UNAMORT LOSS ON REACCQU	199,599	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		105,973
49	1900		DEFERRED TAXES - DIRECT	3,264,256	CAPITAL STRUCTURE	Direct	100%		3,264,256
50								TOTAL	18,228,546
51								TOTAL ASSETS	96,609,569
52									

SUPPORTING SCHEDULES: B-4, B-5, B-6a, B-6b, B-8, B-8a, B-9, B-11, B-12, B-13, B-14, B-15, B-17, B-18

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE BALANCE SHEETS BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN: HISTORIC TEST YEAR - 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) DEC. '06	(6) JAN. '07	(7) FEB. '07	(8) MAR. '07	(9) APR. '07	(10) MAY. '07	(11) JUN. '07	(12) JUL. '07	(13) AUG. '07	(14) SEP. '07	(15) OCT. '07	(16) NOV. '07	(17) DEC. '07	(18) UTILITY 13-MO AVG
1			CAPITALIZATION & LIABILITIES														
2			PROPRIETARY CAPITAL														
3	2010	1	COMMON STOCK ISSUED	(4,650,419)	(4,756,285)	(4,698,796)	(4,744,083)	(4,781,808)	(4,705,029)	(4,669,959)	(4,890,625)	(4,894,833)	(5,224,091)	(5,204,708)	(5,196,959)	(5,526,954)	(4,918,811)
4	2040	1	PREFERRED STOCK ISSUED - $1	(301,177)	(308,033)	(304,310)	(307,243)	(309,686)	(304,714)	(302,442)	(316,733)	(317,006)	(336,330)	(337,075)	(336,573)	(357,944)	(318,559)
5	2070	1	PREMIUM ON COMMON STOCK	(2,834,839)	(2,899,373)	(2,864,329)	(2,891,935)	(2,914,932)	(2,868,128)	(2,846,750)	(2,981,266)	(2,983,831)	(3,184,543)	(3,172,727)	(3,168,003)	(3,369,164)	(2,998,447)
6	2110	1	MISC. PAID IN CAPITAL	(409,632)	(418,957)	(413,893)	(417,882)	(421,206)	(414,442)	(411,353)	(430,791)	(431,161)	(460,164)	(458,457)	(457,774)	(486,842)	(433,274)
7	2140	1	CAPITAL STOCK EXPENSE	215,061	219,957	217,298	219,392	221,137	217,586	215,964	226,169	226,364	241,591	240,694	240,336	255,597	227,473
8	2160	1	UNAPPROP RETAINED EARNINGS	(17,556,737)	(17,956,412)	(17,739,372)	(17,910,346)	(18,052,770)	(17,762,905)	(17,630,505)	(18,463,586)	(18,479,474)	(19,722,523)	(19,649,346)	(19,620,090)	(20,865,920)	(18,569,991)
9	2170	1	COMMON STOCK REACQUIRED	1,234,680	1,262,787	1,247,524	1,259,547	1,269,563	1,249,179	1,239,868	1,298,454	1,299,571	1,386,989	1,381,843	1,379,785	1,467,399	1,305,938
10			TOTAL	(24,303,063)	(24,856,317)	(24,555,878)	(24,792,550)	(24,989,702)	(24,588,453)	(24,405,178)	(25,558,378)	(25,580,370)	(27,301,072)	(27,199,776)	(27,159,278)	(28,883,829)	(25,705,671)
11			LONG-TERM DEBT														
12	2210	1	BONDS	(26,349,894)	(26,949,743)	(26,624,001)	(26,880,605)	(27,094,362)	(26,659,320)	(26,460,609)	(27,710,932)	(27,734,777)	(29,600,398)	(29,490,571)	(29,446,663)	(31,316,457)	(27,870,641)
13																	
14			OTHER NON-CURRENT LIABILITIES														
15	2280	12	GAS STORM RESERVE	-	-	-	-	-	-	-	-	-	(610,069)	(610,069)	(612,774)	(612,774)	(188,130)
16	2280	31	PENSION RESERVE	(1,568,149)	(1,617,983)	(1,667,816)	(1,692,024)	(1,765,258)	(1,838,491)	(1,815,899)	(1,889,132)	(1,832,366)	(1,792,425)	(1,863,731)	(1,935,036)	(1,705,343)	(1,767,973)
17	2280	32	MEDICAL - POST RETIREMENT	(951,330)	(955,347)	(961,110)	(968,008)	(974,036)	(979,750)	(979,586)	(985,300)	(991,385)	(994,415)	(999,722)	(1,005,209)	(826,993)	(967,092)
18	2280	34	401(K) ACCRUAL - COMPANY SHARE	-	-	-	-	-	-	-	-	-	-	-	-	(2,168)	(167)
19	2280	201	ACCRUED LIABILITY INSURANCE	(92,536)	(86,257)	(70,216)	(56,172)	(56,901)	(47,983)	(76,500)	(61,491)	(44,372)	(76,500)	(79,343)	(82,972)	(111,175)	(72,494)
20	2290	1	ACCUM PROV - RATE REFUNDS	(721,400)	(721,400)	(721,400)	(675,000)	(675,000)	(675,000)	(760,182)	(760,182)	(760,182)	(25,000)	(25,000)	(25,000)	(26,325)	(505,467)
21			TOTAL	(3,333,415)	(3,380,987)	(3,420,543)	(3,391,204)	(3,471,194)	(3,541,224)	(3,632,167)	(3,696,106)	(3,628,305)	(3,498,409)	(3,577,866)	(3,660,992)	(3,284,778)	(3,501,323)
22			CURRENT AND ACCRUED LIABILITIES														
23	2310	1	NOTES PAYABLE	(2,258,904)	(2,310,328)	(2,282,403)	(2,304,401)	(2,322,726)	(2,285,431)	(2,268,396)	(2,375,582)	(2,377,627)	(2,537,561)	(2,528,146)	(2,524,382)	(2,684,674)	(2,389,274)
24	2320		ACCOUNTS PAYABLE - FUEL	(4,056,091)	(3,245,535)	(3,944,431)	(3,735,574)	(3,034,925)	(2,189,469)	(2,261,911)	(2,100,683)	(1,744,433)	(1,534,611)	(1,826,143)	(3,264,570)	(3,437,569)	(2,798,150)
25	2320		ACCTS PAY -TRADE, NET OF FUEL	(1,457,601)	(1,183,620)	(1,159,761)	(1,219,101)	(954,734)	(1,132,689)	(1,818,412)	(1,103,363)	(1,383,305)	(1,574,153)	(1,321,481)	(1,070,439)	(1,396,099)	(1,290,366)
26	2320		ACCOUNTS PAYABLE - OTHER	(530,318)	(548,211)	(554,446)	(308,931)	(270,187)	(406,859)	(486,066)	(461,266)	(242,675)	(292,005)	(384,909)	(471,263)	(561,936)	(424,544)
27	2350	1	CUSTOMER DEPOSITS	(5,491,601)	(5,559,620)	(5,604,513)	(5,642,261)	(5,652,617)	(5,631,942)	(5,607,088)	(5,646,460)	(5,649,536)	(5,654,543)	(5,663,446)	(5,677,146)	(5,679,024)	(5,627,678)
28	2360	1	ACC'D PROPERTY TAXES	-	(97,079)	(194,156)	(291,238)	(388,317)	(485,397)	(582,476)	(679,555)	(776,635)	(873,714)	(970,793)	108,144	-	(402,401)
29	2360	2, 3	FLA GROSS REC & FPSC ASSESS TAX	(281,648)	(234,626)	(254,008)	(252,878)	(273,968)	(272,915)	(294,029)	(192,554)	(203,494)	(205,903)	(239,287)	(248,145)	(287,958)	(249,340)
30	2360	5, 6	ACC'D PAYROLL TAXES - F & S UNEMP.	(1,214)	(7,927)	(13,482)	(15,603)	(240)	(479)	(569)	(200)	(465)	(686)	(203)	(438)	(602)	(3,239)
31	2360	8, 9	ACC'D INCOME TAXES	(767,802)	(1,048,761)	(1,307,331)	(1,452,079)	(1,169,666)	(1,254,530)	(774,466)	(931,750)	(1,009,321)	(1,088,626)	(1,216,149)	(1,377,898)	(1,155,224)	(1,119,508)
32	2370	1, 2	ACC'D INTEREST - NOTES	(222,015)	(395,792)	(557,286)	(591,298)	(199,448)	(182,815)	(218,583)	(397,457)	(562,059)	(597,878)	(213,987)	(193,501)	(364,641)	(361,289)
33	2370	3	ACC'D INTEREST- CUSTOM DEPOSITS	(252,938)	(275,365)	(271,153)	(36,006)	(61,729)	(89,836)	(116,926)	(142,931)	(171,206)	(195,565)	(222,523)	(249,036)	(275,305)	(181,578)
34	2380		DIVIDENDS PAY - PREFERRED STOCK	(3,634)	-	-	(3,634)	-	-	(3,634)	-	-	(3,634)	-	-	-	(1,118)
35	2410	2, 3	TAXES PAYABLE - EMPLOYEE W/H	-	-	-	-	-	-	-	-	11	22	22	22	22	7
36	2410	6	TAXES PAYABLE - SALES	(32,052)	(34,415)	(30,668)	(38,707)	(58,268)	(70,019)	(48,383)	(50,401)	(39,007)	(23,780)	(22,691)	(36,484)	(56,408)	(41,637)
37	2410		TAXES PAYABLE - FRANCH & MUNIPLE	(339,725)	(401,420)	(483,418)	(561,414)	(519,604)	(538,174)	(330,751)	(250,192)	(251,367)	(263,710)	(246,519)	(292,586)	(394,629)	(374,886)
38	2420	7	VENDING FUND	(11,225)	(12,253)	(12,708)	(13,625)	(14,380)	(15,457)	(16,022)	(16,796)	(16,074)	(16,292)	(17,144)	(16,861)	(15,730)	(14,967)
39	2420		ACCRUED OUTSIDE LEGAL AND AUDIT	(50,082)	(72,017)	(93,625)	(110,472)	(96,904)	(100,492)	(106,734)	(123,927)	(133,204)	(116,112)	(142,378)	(126,476)	(63,240)	(102,743)
40	2420		MISC CURRENT ACCRUED LIABILITIES	(16,377)	(15,049)	(17,325)	(19,422)	(18,471)	(20,793)	(10,411)	(8,947)	(10,748)	(12,727)	(12,111)	(13,949)	(15,652)	(14,768)
41	2420	1	ACCRUED VACATION	(623,044)	(623,044)	(623,044)	(623,044)	(623,044)	(623,044)	(623,044)	(623,044)	(623,044)	(635,836)	(623,044)	(623,044)	(670,426)	(627,673)
42			TOTAL	(16,396,270)	(16,065,062)	(17,403,758)	(17,219,689)	(15,659,228)	(15,300,341)	(15,567,902)	(15,105,109)	(15,194,188)	(15,627,314)	(15,650,933)	(16,078,053)	(17,059,096)	(16,025,152)
43			DEFERRED CREDITS														
44	2520		CUSTOMER ADVANCES FOR CONSTR	(1,413,893)	(1,422,511)	(1,435,745)	(1,462,728)	(1,544,269)	(1,552,302)	(1,668,155)	(1,660,557)	(1,677,568)	(1,673,738)	(1,785,010)	(1,816,594)	(1,883,514)	(1,615,122)
45	2530	31	ENVIRONMENTAL COSTS - NET OF CUSTOMER PROCEEDS	(149,051)	(187,361)	(215,821)	(237,880)	(275,842)	(306,804)	(332,194)	(363,178)	(396,208)	(410,428)	(449,275)	(470,929)	(481,863)	(328,987)
46	2530	32	ENVIRONMENTAL LIABILITY - PENDING RATE RECOVERY	(8,270,704)	(8,232,675)	(8,194,646)	(8,107,517)	(8,069,488)	(8,031,459)	(7,955,630)	(7,917,601)	(7,879,572)	(7,812,143)	(7,774,114)	(7,736,085)	(7,652,656)	(7,971,868)
47	2530		OVERRECOVERIES - CONSERV & PGA	(3,966,694)	(4,457,623)	(4,038,509)	(4,151,258)	(4,086,196)	(4,392,929)	(4,406,695)	(4,277,619)	(4,195,739)	(3,955,158)	(3,663,691)	(2,533,561)	(1,806,864)	(3,840,965)
48	2530		DEFERRED CREDITS - MISC.	(40,653)	(30,628)	(20,578)	(10,544)	(7,863)	(5,201)	(2,546)	101	105	98	(156)	(154)	-	(9,078)
49	2550		ITC	(210,184)	(206,903)	(203,622)	(200,341)	(197,060)	(193,779)	(190,498)	(187,217)	(183,936)	(180,655)	(177,374)	(174,093)	(170,813)	(190,499)
50	28nn		DEFERRED TAXES	(10,122,510)	(9,948,346)	(9,829,092)	(9,720,347)	(9,617,777)	(9,533,189)	(9,535,557)	(9,446,597)	(9,447,643)	(9,475,978)	(9,459,314)	(9,402,086)	(8,614,977)	(9,550,263)
51			TOTAL	(24,173,689)	(24,486,047)	(23,938,013)	(23,890,615)	(23,798,495)	(24,015,663)	(24,091,275)	(23,852,668)	(23,780,561)	(23,508,002)	(23,308,934)	(22,133,502)	(20,610,687)	(23,506,782)
52			TOTAL CAPITALIZATION & LIABILITIES	(94,556,331)	(95,738,156)	(95,942,193)	(96,174,663)	(95,012,982)	(94,105,001)	(94,157,131)	(95,923,192)	(95,918,201)	(99,535,194)	(99,228,080)	(98,478,487)	(101,154,846)	(96,609,569)
54																	

SUPPORTING SCHEDULES: B-4, B-5, B-6a, B-6b, B-8, B-8a, B-9, B-11, B-12, B-13, B-14, B-15, B-17, B-18

RECAP SCHEDULES: B-2

SCHEDULE B-1 | 13-MONTH AVERAGE BALANCE SHEET - 2007

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE BALANCE SHEETS BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) CONSOLIDATED 13-MO AVG	(6) REFERENCE	(7) ALLOCATION BASIS	(8) ALLOC. %		(9) UTILITY 13-MO AVG
1			CAPITALIZATION & LIABILITIES						
2			PROPRIETARY CAPITAL						
3	2010	1	COMMON STOCK ISSUED	(9,264,492)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(4,918,811)
4	2040	1	PREFERRED STOCK ISSUED - $1	(600,000)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(318,559)
5	2070	1	PREMIUM ON COMMON STOCK	(5,647,522)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(2,998,447)
6	2110	1	MISC. PAID IN CAPITAL	(816,063)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(433,274)
7	2140	1	CAPITAL STOCK EXPENSE	428,441	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		227,473
8	2160	1	UNAPPROP RETAINED EARNINGS	(34,976,250)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(18,569,991)
9	2170	1	COMMON STOCK REACQUIRED	2,459,710	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		1,305,938
10								TOTAL	(25,705,671)
11			LONG-TERM DEBT						
12	2210	1	BONDS	(52,493,846)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(27,870,641)
13									
14			OTHER NON-CURRENT LIABILITIES						
15	2280	12	GAS STORM RESERVE	(188,130)	WORKING CAPITAL	Direct	100%		(188,130)
16	2280	31	PENSION RESERVE	(3,399,949)	WORKING CAPITAL	Payroll	52%		(1,767,973)
17	2280	32	MEDICAL - POST RETIREMENT	(1,896,258)	WORKING CAPITAL	Adj. Gross Profit	51%		(967,092)
18	2280	34	401(K) ACCRUAL - COMPANY SHARE	(321)	WORKING CAPITAL	Payroll	52%		(167)
19	2280	201	ACCRUED LIABILITY INSURANCE	(142,145)	WORKING CAPITAL	Adj. Gross Profit	51%		(72,494)
20	2290	1	ACCUM PROV - RATE REFUNDS	(505,467)	WORKING CAPITAL	Direct	100%		(505,467)
21								TOTAL	(3,501,323)
22			CURRENT AND ACCRUED LIABILITIES						
23	2310	1	NOTES PAYABLE	(4,500,154)	CAPITAL STRUCTURE	Allocated Consolidated Equity	53%		(2,389,274)
24	2320		ACCOUNTS PAYABLE - FUEL	(2,798,150)	WORKING CAPITAL	Direct	100%		(2,798,150)
25	2320		ACCTS PAY -TRADE, NET OF FUEL	(2,530,130)	WORKING CAPITAL	Adj. Gross Profit	51%		(1,290,366)
26	2320		ACCOUNTS PAYABLE - OTHER	(818,763)	WORKING CAPITAL	Adj. Gross Profit / Payroll	52%		(424,544)
27	2350	1	CUSTOMER DEPOSITS	(5,627,678)	CAPITAL STRUCTURE	Direct	100%		(5,627,678)
28	2360	1	ACC'D PROPERTY TAXES	(402,401)	WORKING CAPITAL	Direct	100%		(402,401)
29	2360	2, 3	FLA GROSS REC & FPSC ASSESS TAX	(402,161)	WORKING CAPITAL	Regulated Adj. Gross Profit	62%		(249,340)
30	2360	5, 6	ACC'D PAYROLL TAXES - F & S UNEMP.	(6,229)	WORKING CAPITAL	Payroll	52%		(3,239)
31	2360	8, 9	ACC'D INCOME TAXES	(2,195,113)	WORKING CAPITAL	Adj. Gross Profit	51%		(1,119,508)
32	2370	1, 2	ACC'D INTEREST - NOTES	(708,410)	WORKING CAPITAL	Total Plant	51%		(361,289)
33	2370	3	ACC'D INTEREST- CUSTOM DEPOSITS	(181,578)	WORKING CAPITAL	Direct	100%		(181,578)
34	2380		DIVIDENDS PAY - PREFERRED STOCK	(2,192)	WORKING CAPITAL	Adj. Gross Profit	51%		(1,118)
35	2410	2, 3	TAXES PAYABLE - EMPLOYEE W/H	14	WORKING CAPITAL	Payroll	52%		7
36	2410	6	TAXES PAYABLE - SALES	(41,637)	WORKING CAPITAL	Direct	100%		(41,637)
37	2410		TAXES PAYABLE - FRANCH & MUNIPLE	(374,886)	WORKING CAPITAL	Direct	100%		(374,886)
38	2420	7	VENDING FUND	(14,967)	WORKING CAPITAL	Direct	100%		(14,967)
39	2420		ACCRUED OUTSIDE LEGAL AND AUDIT	(201,457)	WORKING CAPITAL	Adj. Gross Profit	51%		(102,743)
40	2420		MISC CURRENT ACCRUED LIABILITIES	(28,957)	WORKING CAPITAL	Adj. Gross Profit	51%		(14,768)
41	2420	1	ACCRUED VACATION	(1,207,063)	WORKING CAPITAL	Payroll	52%		(627,673)
42								TOTAL	(16,025,152)
43			DEFERRED CREDITS						
44	2520		CUSTOMER ADVANCES FOR CONSTR	(1,615,122)	RATE BASE	Direct	100%		(1,615,122)
45	2530	31	ENVIRONMENTAL COSTS - NET OF CUSTOMER PROCEEDS	(328,987)	WORKING CAPITAL	Direct	100%		(328,987)
47	2530	32	ENVIRONMENTAL LIABILITY - PENDING RATE RECOVERY	(7,971,868)	WORKING CAPITAL	Direct	100%		(7,971,868)
48	2530		OVERRECOVERIES - CONSERV & PGA	(3,840,965)	WORKING CAPITAL	Direct	100%		(3,840,965)
49	2530		DEFERRED CREDITS - MISC.	(9,078)	WORKING CAPITAL	Direct	100%		(9,078)
50	2550		ITC	(190,499)	CAPITAL STRUCTURE	Direct	100%		(190,499)
51	28nn		DEFERRED TAXES	(9,550,263)	CAPITAL STRUCTURE	Direct	100%		(9,550,263)
52								TOTAL	(23,506,782)
53								TOTAL CAPITALIZATION & LIABILITIES	(96,609,569)
54									

SUPPORTING SCHEDULES: B-4, B-5, B-6a, B-6b, B-8, B-8a, B-9, B-11, B-12, B-13, B-14, B-15, B-17, B-18

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING A 13-MONTH AVERAGE RATE BASE AS ADJUSTED FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	ACCT	UTILITY PLANT	AVERAGE PER BOOKS	ADJUSTMENT	ADJUSTED AVERAGE
1	1010	PLANT IN SERVICE	97,425,925	(3,753,653)	93,672,272
2	1070	CWIP UTILITY	2,835,239	-	2,835,239
3	1070	CWIP - ALLOCATED COMMON	121,454	-	121,454
4	1140	ACQUISITION ADJUSTMENT	1,816,579	(552,803)	1,263,776
4	1180	PLANT IN SERVICE ALLOCATED COMMON	2,888,025	-	2,888,025
6					
7		TOTAL PLANT	105,087,222	(4,306,456)	100,780,766
8					
9		DEDUCTIONS			
10					
11	1080	Accumulated Reserve - Utility	(31,977,603)	466,889	(31,510,714)
12	1150	Accumulated Amortization - Acquisition Adjustment	(390,238)	(92,214)	(482,452)
13	1190	Accumulated Reserve - Allocated Common	(1,004,274)		(1,004,274)
14	2520	Customer Advances for Construction	(1,615,122)		(1,615,122)
15					
16		TOTAL DEDUCTIONS	(34,987,237)	374,675	(34,612,562)
17					
18		PLANT NET	70,099,985	(3,931,781)	66,168,204
19					
20		ALLOWANCE FOR WORKING CAPITAL			
21					
22		BALANCE SHEET METHOD	(3,069,725)	(3,579,507)	(6,649,232)
23					
24		TOTAL RATE BASE	67,030,260	(7,511,288)	59,518,973
25					
26					
27		NET OPERATING INCOME	3,902,175	48,642	3,950,817
28					
29					
30		RATE OF RETURN	5.82%		6.64%

SUPPORTING SCHEDULES: B-1, B-3, B-4, B-5, B-6, B-7, B-8, B-9, B-10, B-11, B-12, B-13, C-1

RECAP SCHEDULES:

SCHEDULE B-3	RATE BASE BASE ADJUSTMENTS	PAGE 1 OF 2
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: LIST AND EXPLAIN ALL PROPOSED ADJUSTMENT TO THE 13-MONTH RATE BASE FOR THE HISTORIC BASE YEAR. CALCULATE THE REVENUE IMPACT OF EACH ADJUSTMENT, ASSUMING THE REQUESTED RATE OF RETURN AND EXPANSION FACTOR REMAIN CONSTANT.	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/07
COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION		WITNESS: Mesite
DOCKET NO: 080366-GU		

(1) ADJUSTMENT NO.	(2) ADJUSTMENT ACCOUNT	(3) ADJUSTMENT TITLE	(4) REASON FOR ADJUSTMENT	(5) COMMISSION ADJUSTMENT	(6) NON-UTILITY AMOUNT	(7) REGULATED AMOUNT	(8) INCREASE/DECREASE IN REVENUE REQUIREMENT
						FACTOR =	**0.094500613**
		UTILITY PLANT					
1	1010	Non-Regulated Plant - Operations	Allocated Portion of Utility Plant allocated to Non-Utility (Page 2)	(1,853,653)	-0-	(1,853,653)	(175,171)
2	1010.3031	Non-Compete Agreement	Commission Adjustment - Eliminated from Rate Base	(1,900,000)	-0-	(1,900,000)	(179,551)
3	1140.2	Goodwill	Commission Adjustment - Eliminated from Rate Base	(552,803)	-0-	(552,803)	(52,240)
		TOTAL UTILITY PLANT ADJUSTMENTS		(4,306,456)	-	(4,306,456)	(406,963)
		DEDUCTIONS					
4	1080	Non-Regulated Reserve - Operations	Allocated Portion of Utility Reserve allocated to Non-Utility (Page 2)	466,889	-0-	466,889	44,121
5	1150.1	Unrecorded Reserve - Acquisition Adjustment	1/1/02 through 11/17/04 Amortization Reserve Not Booked	(92,214)	-0-	(92,214)	(8,714)
		TOTAL DEDUCTIONS ADJUSTMENTS		374,675	-	374,675	35,407
		NET ADJUSTMENTS TO PLANT		(3,931,781)	-	(3,931,781)	(371,556)
		ALLOWANCE FOR WORKING CAPITAL					
6	2290.1	Over Earnings Refund	Commission Adjustment - Eliminated from Rate Base	505,467	-0-	505,467	47,767
7	1540.1	Operating Materials & Supplies Inventory	Allocated Portion of Inventory Allocated to Non-Utility Operations	(44,688)	-0-	(44,688)	(4,223)
8	1860.4	Other Deferred Debits - AEP	Commission Adjustment - Eliminated from Rate Base	(3,973,813)	-0-	(3,973,813)	(375,528)
9	1860.1	Other Deferred Debits - Rate Case Expense	Commission Adjustment - Eliminated 50% from Rate Base	(66,473)	-0-	(66,473)	(6,282)
		TOTAL WORKING CAPITAL ADJUSTMENTS		(3,579,507)	-	(3,579,507)	(338,266)
		TOTAL RATE BASE ADJUSTMENTS		(7,511,288)	-	(7,511,288)	(709,821)

SUPPORTING SCHEDULES: B-1, B-4, B-6, B-9, B-13

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: LIST AND EXPLAIN ALL PROPOSED ADJUSTMENT TO THE 13-MONTH RATE BASE FOR THE HISTORIC BASE YEAR. CALCULATE THE REVENUE IMPACT OF EACH ADJUSTMENT, ASSUMING THE REQUESTED RATE OF RETURN AND EXPANSION FACTOR REMAIN CONSTANT.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

Line	(1) ADJUSTMENT NO.	(2) ADJUSTMENT ACCOUNT	(3) DESCRIPTION	(4) PLANT BALANCE	(5) OVERALL AVG % NON-REG	(6) NON-REG AMOUNT	(7) RESERVE BALANCE	(8) OVERALL AVG % NON-REG	(9) NON-REG AMOUNT
1									
2	1	1010/1080	Non-Regulated Plant/Reserve	1010 - Plant, Non-Regulated			1080 - Reserve, Non-Regulated		
3									
4		303	MISC. INTANGIBLE PLANT	213,641	0%	-	(99,812)	0%	-
5		3031	INTANGIBLE NON-COMPETE AGREEMENT	1,900,000	0%	-	-	0%	-
6		374	LAND	101,108	11%	(10,771)	-	0%	-
7		3741	LAND RIGHTS	12,910	0%	-	7,872	40%	(3,150)
8		375	STRUCTURES AND IMPROVEMENTS	476,934	19%	(90,957)	(246,734)	19%	46,451
9		3761	MAINS- PLASTIC	23,251,922	0%	-	(4,231,261)	0%	-
10		3762	MAINS -OTHER-(CAST IRON, STEEL)	27,099,145	0%	-	(13,997,957)	0%	-
11		378	MEASURE/REGULATOR EQP.-GENERAL	306,196	0%	-	(84,911)	0%	-
12		379	MEASURE/REG EQP - CITY GATE STN	2,014,726	0%	-	(436,598)	0%	-
13		3801	SERVICES - PLASTIC	20,548,806	0%	-	(5,186,506)	0%	-
14		3802	SERVICES - OTHER- CAST IRON,	2,160,833	0%	-	(1,869,483)	0%	-
15		381	METERS	5,598,572	0%	-	(2,074,820)	0%	-
16		382	METER INSTALLATIONS	2,616,465	0%	-	(715,123)	0%	-
17		383	HOUSE REGULATORS	1,849,528	0%	-	(703,658)	0%	-
18		384	HOUSE REGULATOR	877,935	0%	-	(258,893)	0%	-
19		385	INDUST MEASURING/REG STATION EQP	48,619	0%	-	(12,158)	0%	-
20		387	OTHER EQUIPMENT	554,979	17%	(93,659)	(108,215)	17%	17,983
21		389	LAND AND LAND RIGHTS	492,038	22%	(106,028)	-	0%	-
22		3892	RIGHTS-OF-WAY	-	0%	-	-	0%	-
23		390	STRUCTURES AND IMPROVEMENTS	1,402,139	25%	(344,766)	(320,266)	25%	79,045
24		3911	OFFICE FURNITURE	111,561	22%	(25,019)	(28,303)	23%	6,441
25		3912	OFFICE MACHINES	49,706	22%	(11,075)	(25,092)	24%	6,024
26		3913	E D P EQUIPMENT	598,450	21%	(125,293)	(60,149)	12%	6,959
27		391305	COMPUTER SOFTWARE	515,249	21%	(109,496)	(62,848)	22%	13,516
28		3921	TRANSP EQUIP-CARS	175,284	19%	(34,040)	(59,138)	19%	11,487
29		3922	TRANS - LIGHT TRUCK, VAN	3,354,387	21%	(698,596)	(956,192)	21%	198,763
30		3923	TRANS - HEAVY TRUCKS	-	0%	-	-	0%	-
31		3924	TRANS - TRAILERS	44,518	20%	(8,979)	(26,441)	20%	5,237
32		393	STORES EQUIPMENT	9,562	19%	(1,817)	(9,137)	19%	1,736
33		394	TOOLS, SHOP & GARAGE EQUIPMENT	302,472	17%	(50,848)	(159,879)	17%	27,562
34		396	POWER OPERATED EQUIPMENT	328,627	17%	(55,975)	(114,633)	17%	20,057
35		397	COMMUNICATION EQUIPMENT	263,098	21%	(55,347)	(123,693)	21%	25,953
36		398	MISCELLANEOUS EQUIPMENT	146,515	21%	(30,987)	(13,578)	21%	2,825
37		399	TANGIBLE PROPERTY	-	0%	-	-	0%	-
38			TOTALS	97,425,925		(1,853,653)	(31,977,606)		466,889

SCHEDULE B-4 | MONTHLY PLANT BALANCES TEST YEAR - 13 MONTHS |

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE MONTHLY PLANT BALANCES FOR EACH ACCOUNT OR SUB-ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

Line	(1) Acct 1010	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
1		INTANGIBLE PLANT														
2	303	MISC. INTANGIBLE PLANT	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641	213,641
3	3031	INTANGIBLE NON-COMPETE AGREEMENT	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000	1,900,000
4		TOTAL INTANGIBLE PLANT	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641	2,113,641
5																
6		DISTRIBUTION PLANT														
7	374	LAND	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108	101,108
8	3741	LAND RIGHTS	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910
9	375	STRUCTURES AND IMPROVEMENTS	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934	476,934
10	3761	MAINS- PLASTIC	21,896,250	22,022,789	22,345,112	22,500,142	22,588,998	22,752,069	23,188,093	23,655,846	23,785,353	24,124,405	24,281,685	24,353,309	24,780,938	23,251,922
11	3762	MAINS -OTHER-(CAST IRON, STEEL)	27,146,297	27,145,281	27,148,563	27,158,429	27,121,588	27,116,671	27,115,440	27,071,047	27,071,877	27,069,417	27,069,693	27,053,609	27,000,981	27,099,146
12	378	MEASURE/REGULATOR EQP.-GENERAL	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,191	306,257	306,196
13	379	MEASURE/REG EQP - CITY GATE STN	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,014,157	2,017,425	2,018,286	2,014,726
14	3801	SERVICES - PLASTIC	19,836,765	19,981,763	20,107,585	20,198,105	20,299,996	20,383,519	20,508,202	20,621,824	20,758,843	20,866,676	20,991,163	21,132,811	21,447,227	20,548,806
15	3802	SERVICES - OTHER- CAST IRON, ETC	2,177,669	2,177,669	2,177,669	2,169,145	2,165,526	2,160,082	2,158,026	2,155,429	2,153,248	2,151,879	2,148,911	2,148,396	2,147,193	2,160,834
17	381	METERS	5,563,932	5,574,714	5,564,562	5,560,047	5,545,547	5,642,480	5,599,277	5,557,782	5,552,453	5,608,049	5,639,159	5,684,976	5,688,460	5,598,572
18	382	METER INSTALLATIONS	2,443,399	2,460,152	2,474,766	2,497,857	2,509,481	2,601,574	2,625,623	2,683,480	2,701,306	2,726,093	2,737,124	2,752,640	2,800,556	2,616,465
19	383	HOUSE REGULATORS	1,735,639	1,735,639	1,810,317	1,813,214	1,811,737	1,812,310	1,810,476	1,814,655	1,900,455	1,927,460	1,949,970	1,960,389	1,961,609	1,849,528
20	384	HOUSE REGULATOR INSTALLATIONS	857,113	860,838	863,742	866,272	869,066	870,951	874,355	876,352	887,878	891,073	893,855	897,500	904,154	877,935
21	385	INDUST MEASURING/REG STATION EQP	48,521	48,521	48,521	48,521	48,521	48,521	48,521	48,521	48,521	48,521	48,521	49,308	49,008	48,619
22	387	OTHER EQUIPMENT	526,784	532,042	540,310	541,171	547,950	553,154	557,247	558,088	559,606	559,606	559,606	562,041	617,121	554,979
23		TOTAL DISTRIBUTION PLANT	85,143,669	85,450,708	85,992,447	86,264,203	86,419,710	86,852,631	87,396,560	87,954,324	88,330,840	88,884,479	89,230,987	89,509,547	90,312,742	87,518,680
24		GENERAL PLANT														
25	389	LAND AND LAND RIGHTS	219,333	219,333	219,333	219,333	219,333	219,333	219,333	219,333	219,333	219,333	219,333	219,333	3,764,497	492,038
26	3892	RIGHTS-OF-WAY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	390	STRUCTURES AND IMPROVEMENTS	1,394,552	1,394,552	1,394,552	1,399,344	1,399,344	1,399,344	1,399,344	1,401,335	1,417,041	1,417,159	1,403,742	1,403,742	1,403,742	1,402,138
28	3911	OFFICE FURNITURE	109,891	109,891	109,891	113,049	113,049	113,049	113,049	113,049	113,049	110,582	110,582	110,582	110,582	111,561
29	3912	OFFICE MACHINES	39,555	39,555	39,555	46,903	46,903	46,903	46,903	46,903	46,903	46,903	66,396	66,396	66,396	49,706
30	3913	E D P EQUIPMENT	580,960	580,960	580,960	577,164	575,559	574,353	605,148	619,336	617,322	608,111	606,141	614,812	639,030	598,450
31	391305	COMPUTER SOFTWARE	484,507	484,507	486,227	486,227	523,166	529,063	529,063	529,063	529,063	529,063	529,063	529,063	530,167	515,249
32	3921	TRANSP EQUIP-CARS	178,003	178,003	178,003	178,003	178,003	178,003	178,003	195,749	195,749	195,749	195,749	124,837	124,837	175,284
33	3922	TRANS - LIGHT TRUCK, VAN	3,341,378	3,341,378	3,341,378	3,341,378	3,343,644	3,346,202	3,346,202	3,346,202	3,346,202	3,391,070	3,404,044	3,187,418	3,530,539	3,354,387
34	3923	TRANS - HEAVY TRUCKS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	3924	TRANS - TRAILERS	43,384	43,384	43,384	43,384	43,384	44,141	44,141	44,141	44,141	47,709	47,709	44,912	44,912	44,517
36	393	STORES EQUIPMENT	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562	9,562
37	394	TOOLS, SHOP & GARAGE EQUIPMENT	283,133	283,415	283,415	303,210	299,148	308,255	308,255	309,778	312,208	303,864	303,864	316,793	316,793	302,472
38	396	POWER OPERATED EQUIPMENT	327,924	327,924	327,924	327,924	327,924	327,924	327,924	332,904	332,904	332,904	332,904	322,531	322,531	328,627
39	397	COMMUNICATION	269,555	269,555	269,555	269,555	269,555	269,555	269,555	270,819	270,819	270,819	270,819	222,676	227,433	263,098
40	398	MISCELLANEOUS EQUIPMENT	144,505	144,505	144,505	144,505	144,505	144,505	144,505	144,505	144,505	154,485	149,887	149,887	149,887	146,515
41	399	TANGIBLE PROPERTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42		TOTAL GENERAL PLANT	7,426,242	7,426,524	7,428,244	7,459,541	7,493,079	7,510,192	7,540,987	7,582,679	7,598,801	7,637,313	7,649,795	7,322,544	11,240,908	7,793,604
43																
44		TOTAL UTILITY PLANT	94,683,552	94,990,873	95,534,332	95,837,385	96,026,430	96,476,464	97,051,188	97,650,644	98,043,282	98,635,433	98,994,423	98,945,732	103,667,291	97,425,925

SUPPORTING SCHEDULES: | RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE SHOWING THE REGULATED AND NON-REGULATED ITEMS OF COMMON PLANT WITH THE 13 MONTH AVERAGE OF THE HISTORIC BASE YEAR SEGREGATED BY THE AMOUNTS ACCORDING TO REGULATED AND NON-REGULATED ITEMS. THE METHOD OF ALLOCATING BETWEEN REGULATED AND NON-REGULATED PORTIONS SHALL BE DESCRIBED.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1) Acct 1180	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
303	MISC. INTANGIBLE PLANT	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833
389	LAND AND LAND RIGHTS	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926	341,926
390	STRUCTURES AND IMPROVEMENTS	2,114,103	2,115,061	2,115,061	2,115,061	2,162,477	2,162,477	2,162,477	2,162,477	2,165,405	2,168,443	2,168,443	2,170,393	2,196,700	2,152,198
3911	OFFICE FURNITURE	37,920	37,920	37,920	37,920	37,920	37,920	37,920	37,920	37,920	37,920	37,920	37,920	39,509	38,042
3912	OFFICE MACHINES	142,340	142,340	142,340	142,340	142,340	141,388	143,866	143,866	143,866	146,347	126,854	126,854	126,854	139,353
3913	E D P EQUIPMENT	492,102	492,102	492,102	580,956	581,571	723,483	763,784	742,581	744,596	748,222	746,409	724,502	723,852	658,174
391305	COMPUTER SOFTWARE	1,717,058	1,717,058	1,717,860	1,752,492	1,752,492	1,753,721	1,755,703	1,755,703	1,762,228	1,762,228	1,762,228	1,762,228	1,762,228	1,748,710
3921	TRANSP EQUIP-CARS	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127	84,127
3922	TRANS-LIGHT TRUCK, VAN	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669	124,669
397	COMMUNICATION EQUIPMENT	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955	116,955
398	MISCELLANEOUS EQUIPMENT	6,776	6,776	6,776	6,776	6,776	6,776	9,758	9,758	9,758	9,758	9,758	9,758	9,758	8,382
399	TANGIBLE PROPERTY	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969	22,969
	TOTAL	5,202,778	5,203,736	5,204,538	5,328,024	5,376,055	5,518,244	5,565,987	5,544,784	5,556,252	5,565,397	5,544,091	5,524,134	5,551,380	5,437,338

(1) Acct 1180	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
	ALLOCATED TO NATURAL GAS - SEE BELOW FOR ALLOCATION PERCENTAGES														
303	MISC. INTANGIBLE PLANT	990	990	990	990	990	990	990	990	990	990	990	990	990	990
389	LAND AND LAND RIGHTS	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640	184,640
390	STRUCTURES AND IMPROVEMENTS	1,141,616	1,142,133	1,142,133	1,142,133	1,167,738	1,167,738	1,167,738	1,167,738	1,169,319	1,170,959	1,170,959	1,172,012	1,186,218	1,162,187
3911	OFFICE FURNITURE	20,477	20,477	20,477	20,477	20,477	20,477	20,477	20,477	20,477	20,477	20,477	20,477	21,335	20,543
3912	OFFICE MACHINES	76,864	76,864	76,864	76,864	76,864	76,350	77,688	77,688	77,688	79,027	68,501	68,501	68,501	75,251
3913	E D P EQUIPMENT	255,893	255,893	255,893	302,097	302,417	376,211	397,168	386,142	387,190	389,075	388,133	376,741	376,403	342,250
391305	COMPUTER SOFTWARE	892,870	892,870	893,287	911,296	911,296	911,935	912,966	912,966	916,359	916,359	916,359	916,359	916,359	909,329
3921	TRANSP EQUIP-CARS	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429	45,429
3922	TRANS-LIGHT TRUCK, VAN	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321	67,321
397	COMMUNICATION EQUIPMENT	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156	63,156
398	MISCELLANEOUS EQUIPMENT	3,659	3,659	3,659	3,659	3,659	3,659	5,269	5,269	5,269	5,269	5,269	5,269	5,269	4,526
399	TANGIBLE PROPERTY	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403	12,403
	TOTAL	2,765,317	2,765,834	2,766,251	2,830,464	2,856,388	2,930,308	2,955,243	2,944,218	2,950,240	2,955,105	2,943,636	2,933,298	2,948,024	2,888,025

(1) Acct 1180	(2) DESCRIPTION	(3) 13-MO AVG	(4) ALLOCATE TO UTILITY ALLOC. %	(5) ALLOCATE TO UTILITY 13-MO AVG	(6) NON-UTILITY ALLOC. %	(7) NON-UTILITY 13-MO AVG	(8) ALLOCATION METHOD
303	MISC. INTANGIBLE PLANT	1,833	54%	990	46%	843	Consolidated Plant Less EDP & Software
389	LAND AND LAND RIGHTS	341,926	54%	184,640	46%	157,286	Consolidated Plant Less EDP & Software
390	STRUCTURES AND IMPROVEMENTS	2,152,198	54%	1,162,187	46%	990,011	Consolidated Plant Less EDP & Software
3911	OFFICE FURNITURE	38,042	54%	20,543	46%	17,499	Consolidated Plant Less EDP & Software
3912	OFFICE MACHINES	139,353	54%	75,251	46%	64,102	Consolidated Plant Less EDP & Software
3913	E D P EQUIPMENT	658,174	52%	342,250	48%	315,924	Consolidated EDP & Software
391305	COMPUTER SOFTWARE	1,748,710	52%	909,329	48%	839,381	Consolidated EDP & Software
3921	TRANSP EQUIP-CARS	84,127	54%	45,429	46%	38,698	Consolidated Plant Less EDP & Software
3922	TRANS-LIGHT TRUCK, VAN	124,669	54%	67,321	46%	57,348	Consolidated Plant Less EDP & Software
397	COMMUNICATION EQUIPMENT	116,955	54%	63,156	46%	53,799	Consolidated Plant Less EDP & Software
398	MISCELLANEOUS EQUIPMENT	8,382	54%	4,526	46%	3,856	Consolidated Plant Less EDP & Software
399	TANGIBLE PROPERTY	22,969	54%	12,403	46%	10,566	Consolidated Plant Less EDP & Software
	TOTAL	5,437,338		2,888,025		2,549,313	

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE SHOWING A DETAILED DESCRIPTION OF EACH PARCEL OF LAND AND STRUCTURE BY ADDRESS OF COMMON UTILITY PLANT BY PRIMARY ACCOUNT. ALSO, SHOW THE 13-MONTH AVERAGE PLANT AND ACCUMULATED DEPRECIATION AMOUNT ALLOCATED TO UTILITY AND NON-UTILITY OPERATIONS AND THE ALLOCATION BASIS.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
					PLANT IN SERVICE			ACCUMULATED RESERVE				
1	Acct 1180	DESCRIPTION & ADDRESS		UTILITY	NON-UTILITY	TOTAL	UTILITY	NON-UTILITY	TOTAL		BASIS FOR ALLOCATION	
2	374	LAND										
3		None										
4			TOTAL									
5												
6	375	STRUCTURES AND IMPROVEMENTS										
7		None										
8			TOTAL									
9												
10	389	LAND										
11		Land Containing Corporate Office, Lot 1 & Lot 2 - 401 S. Dixie Hgwy, West Palm Beach, Fl		78,714	67,053	145,767	-	-	-		Consolidated Plant Less EDP & Software	
12												
13		Land Adjacent To Corporate Office - Lot 3 - Fern St, West Palm Beach, Fl		105,926	90,233	196,159	-	-	-		Consolidated Plant Less EDP & Software	
14			TOTAL	184,640	157,286	341,926	-	-	-			
15												
16	390	STRUCTURES AND IMPROVEMENTS										
17		General Office - 401 S. Dixie Hgwy, West Palm Beach, Fl		1,162,187	990,011	2,152,198	(244,920)	(208,635)	(453,555)		Consolidated Plant Less EDP & Software	
18			TOTAL	1,162,187	990,011	2,152,198	(244,920)	(208,635)	(453,555)			

SUPPORTING SCHEDULES: B-11, B-5, B-1

RECAP SCHEDULES: B-1, B-2, B-5

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE FOLLOWING INFORMATION RELATING TO EACH ACQUISITION ADJUSTMENT INCLUDED IN THE RATE CASE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

A	1. Describe the property acquired which resulted in the acquisition adjustment.
B	Sanford Distribution System
C	Deland Distribution System
D	Atlantis Distribution System
E	University Park Distribution System
F	North Palm Beach Distibution System
	South Florida Natural Gas (SFNG)
A	2. Date of acquisition.
B	January 1, 1965
C	June 1, 1967
D	July 31, 1967
E	July 22, 1980
F	October 22, 1975
	December 14, 2001 (Effective 11/18/04)
A	3. Amount of acquisition adjustment.
B	102,833
C	230,090
D	7,717
E	(24,389)
F	(12,851)
	960,376
A	4. Was the property purchased from a related party?
B	No
C	No
D	No
E	No
F	No
	No
A	5. Has the acquisition adjustment been approved by the Commission?
B	Yes
C	Yes
D	No
E	No
F	No
	Yes
A	6. Provide the Docket No. and Order No. approving the acquisition adjustment.
B	Letter 12/28/65 from F.H. Roming
C	Not able to locate letter
D	None
E	None
F	None
	2004 Rate Proceeding, Docket No. 040216-GU, Order No, PSC-04.1110-PAA-GU, Effective 11/18/04

SCHEDULE B-6 | ACQUISITION ADJUSTMENT |

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE FOLLOWING INFORMATION RELATING TO EACH ACQUISITION ADJUSTMENT INCLUDED IN THE RATE CASE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

WITNESS: Mesite

(1)	(2) ACCT	(3) SUB		(4) DESCRIPTION	(5) DEC. '06	(6) JAN. '07	(7) FEB. '07	(8) MAR. '07	(9) APR. '07	(10) MAY. '07	(11) JUN. '07	(12) JUL. '07	(13) AUG. '07	(14) SEP. '07	(15) OCT. '07	(16) NOV. '07	(17) DEC. '07	(18) 13-MO AVG
1																		
2	1140	1		**ACQUISITION ADJUSTMENT**														
3			A.	Sanford Distribution System	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833	102,833
4			B.	Deland Distribution System	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090	230,090
5			C.	Atlantis Distribution System	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717	7,717
6			D.	University Park Distribution System	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)	(24,389)
7			E.	North Palm Beach Distribution System	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)	(12,851)
8			F.	South Florida Natural Gas (SFNG)	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376	960,376
9				TOTAL	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776	1,263,776
10																		
2	1140	2		**ACQUISITION ADJUSTMENT**														
3			F.	Portion of South Florida Natural Gas (SFNG) - Eliminated from Rate Base	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803	552,803
11	1150	1		**RESERVE-ACQ ADJUSTMENT**														
12			A.	Sanford Distribution System	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)	(102,833)
13			B.	Deland Distribution System	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)	(230,090)
14			C.	Atlantis Distribution System	(6,389)	(6,403)	(6,416)	(6,430)	(6,443)	(6,457)	(6,470)	(6,484)	(6,497)	(6,511)	(6,524)	(6,538)	(6,551)	(6,470)
15			D.	University Park Distribution System	20,544	20,599	20,654	20,709	20,763	20,818	20,873	20,928	20,983	21,038	21,093	21,148	21,203	20,873
16			E.	North Palm Beach Distribution System	11,934	11,972	12,010	12,049	12,087	12,125	12,163	12,202	12,240	12,278	12,316	12,355	12,393	12,163
17			F.	South Florida Natural Gas (SFNG)	(67,852)	(70,520)	(73,188)	(75,856)	(78,524)	(81,192)	(83,860)	(86,528)	(89,480)	(91,864)	(94,532)	(97,200)	(99,868)	(83,882)
18				TOTAL	(374,687)	(377,275)	(379,863)	(382,452)	(385,040)	(387,628)	(390,216)	(392,805)	(395,677)	(397,981)	(400,570)	(403,158)	(405,746)	(390,239)
19																		
20	4060	1		**AMORTIZATION-ACQ ADJUSTMENT**														
21			A.	Sanford Distribution System		-	-	-	-	-	-	-	-	-	-	-	-	-
22			B.	Deland Distribution System		-	-	-	-	-	-	-	-	-	-	-	-	-
23			C.	Atlantis Distribution System		14	14	14	14	14	14	14	14	14	14	14	14	162
24			D.	University Park Distribution System		(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(659)
25			E.	North Palm Beach Distribution System		(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(459)
26			F.	South Florida Natural Gas (SFNG)		2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	32,016
27				TOTAL		2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	31,060

SUPPORTING SCHEDULES: B-1

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:PROVIDE A SCHEDULE SHOWINGPROPERTY HELD FOR FUTURE USE BY MONTH AND BY ITEM FOR THE THIRTEEN MONTH PERIOD ENDING WITH THE LAST MONTH OF THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

LINE NO.	ACCT. NO.	DESCRIPTION
1		
2		NONE
3		
4		
5		
6		
7		TOTAL

SUPPORTING SCHEDULES: B-1

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION:PROVIDE A SCHEDULE SHOWINGPROPERTY HELD FOR FUTURE USE BY MONTH AND BY ITEM FOR THE THIRTEEN MONTH PERIOD ENDING WITH THE LAST MONTH OF THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	DESCRIPTION	DATE OF ACQUISITION	LOCATION	REASON FOR PURCHASE	EXPENDITURES AS OF THE END OF THE HISTORIC BASE YEAR
1		NONE			

	DATE CONSTRUCTION IS TO COMMENCE		DATE TO BE PLACED IN SERVICE	INDICATE CURRENT USE	ITEMS INCLUDED IN RATE BASE
2		NONE			

SUPPORTING SCHEDULES: B-1

RECAP SCHEDULES: B-7 p.1

SCHEDULE B-8 | CONSTRUCTION WORK IN PROGRESS |

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE, SHOWING, BY MONTH, CONSTRUCTION WORK IN PROGRESS SEGREGATED BY TEMS ON WHICH ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) WAS CHARGED AND ON WHICH NO AFUDC WAS CHARGED. THE SCHEDULE SHALL INCLUDE A DESCRIPTION OF THE COMPANY'S POLICY AS TO WHICH JOBS RECEIVED AFUDC, TOGETHER WITH THE CALCULATIONS SUPPORTING THE AFUDC RATES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

WITNESS: Mesite

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

	(1) Acct 1070	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
1		UTILITY CWIP - AFUDC NOT CHARGED														
2	303	MISC. INTANGIBLE PLANT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	3031	INTANGIBLE NON-COMPETE AGREEMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	374	LAND	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	3741	LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	375	STRUCTURES AND IMPROVEMENTS	4,793	4,793	4,793	-	-	-	-	-	-	-	-	-	-	1,106
7	3761	MAINS- PLASTIC	818,338	1,045,369	882,380	1,051,620	1,286,347	1,356,396	1,349,865	1,050,142	1,166,253	1,402,077	1,155,721	1,246,178	957,651	1,136,026
8	3762	MAINS -OTHER-(CAST IRON, STEEL)	12,588	12,406	14,240	29,182	9,203	(11,062)	(4,525)	38,261	52,950	56,262	57,557	57,667	94,755	32,268
9	378	MEASURE/REGULATOR EQP.-GENERAL	-	-	-	-	-	-	-	-	-	-	3,776	3,873	3,873	886
10	379	MEASURE/REG EQP - CITY GATE STN	-	-	-	-	-	-	-	4,966	4,966	4,966	4,966	4,966	4,966	2,292
11	3801	SERVICES - PLASTIC	23,641	28,897	24,706	42,095	46,170	85,688	137,655	100,066	87,524	330,815	340,635	364,234	122,326	133,419
12	3802	SERVICES - OTHER- CAST IRON, ETC	-	-	-	-	-	379	379	379	379	379	379	379	379	233
13	381	METERS	-	-	(488)	-	-	-	-	-	-	1,812	1,812	1,812	-	381
14	382	METER INSTALLATIONS	-	-	-	-	-	-	-	-	-	31,192	32,242	32,427	3,576	7,649
15	383	HOUSE REGULATORS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	384	HOUSE REGULATOR INSTALLATIONS	-	-	-	-	-	-	-	-	-	2,366	2,366	2,366	96	553
17	385	INDUST MEASURING/REG STATION EQP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	387	OTHER EQUIPMENT	-	-	-	-	6,766	6,766	-	-	11,809	17,636	29,354	55,080	-	9,801
19	389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	3,526,662	3,526,662	3,529,594	3,544,495	3,544,495	-	1,359,378
20	3892	RIGHTS-OF-WAY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	390	STRUCTURES AND IMPROVEMENTS	-	-	-	-	-	12,526	13,166	13,417	-	-	-	-	-	3,008
22	3911	OFFICE FURNITURE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	3912	OFFICE MACHINES	7,349	7,349	7,349	-	-	-	-	-	-	-	-	-	-	1,696
24	3913	E D P EQUIPMENT	-	-	-	-	24,308	24,308	24,308	-	-	-	63,015	64,215	65,206	20,412
25	391305	COMPUTER SOFTWARE	2,460	-	-	-	-	-	-	-	-	-	-	13,430	13,430	2,255
26	3921	TRANSP EQUIP-CARS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	3922	TRANS - LIGHT TRUCK, VAN	-	-	-	-	-	-	56,044	60,909	280,007	353,195	342,296	343,067	-	110,424
28	3923	TRANS - HEAVY TRUCKS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	3924	TRANS - TRAILERS	-	-	-	-	3,568	3,568	3,568	3,568	3,568	-	-	-	-	1,372
30	393	STORES EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	394	TOOLS, SHOP & GARAGE EQUIPMENT	-	19,795	19,795	-	5,065	250	250	-	-	-	-	-	-	3,473
32	396	POWER OPERATED EQUIPMENT	-	-	-	-	-	-	-	-	-	12	12	12	12,712	981
33	397	COMMUNICATION	-	-	-	-	-	-	-	698	698	2,054	4,757	4,757	-	997
34	398	MISCELLANEOUS EQUIPMENT	-	-	-	5,816	5,915	9,995	9,980	9,980	9,980	-	10,753	11,878	11,878	6,629
35	399	TANGIBLE PROPERTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		TOTAL UTILITY CWIP - AFUDC NOT CHARGED	869,169	1,118,609	952,775	1,128,713	1,387,342	1,488,814	1,590,690	4,809,048	5,144,796	5,732,360	5,594,136	5,750,836	1,290,848	2,835,239
37																
38		UTILITY CWIP - AFUDC CHARGED														
39		NONE- FPUC DOES NOT CHARGE AFUDC														

SUPPORTING SCHEDULES: | RECAP SCHEDULES: B-1

SCHEDULE B-8 | CONSTRUCTION WORK IN PROGRESS |

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE, SHOWING, BY MONTH, CONSTRUCTION WORK IN PROGRESS SEGREGATED BY TEMS ON WHICH ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) WAS CHARGED AND ON WHICH NO AFUDC WAS CHARGED. THE SCHEDULE SHALL INCLUDE A DESCRIPTION OF THE COMPANY'S POLICY AS TO WHICH JOBS RECEIVED AFUDC, TOGETHER WITH THE CALCULATIONS SUPPORTING THE AFUDC RATES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1) Acct 1070	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
	COMMON PLANT - AFUDC NOT CHARGED														
	INTANGIBLE PLANT														
303	MISC. INTANGIBLE PLANT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
390	STRUCTURES AND IMPROVEMENTS	13,317	45,278	46,244	45,261	-	-	5,262	26,646	31,340	67,092	103,148	124,376	152,731	50,823
3911	OFFICE FURNITURE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3912	OFFICE MACHINES	-	-	-	-	-	-	-	-	-	-	-	7,977	7,977	1,227
3913	E D P EQUIPMENT	232,458	234,028	237,401	233,593	235,338	125,296	30,971	18,224	18,482	6,909	6,909	7,354	14,187	107,781
391305	COMPUTER SOFTWARE	58,701	58,701	61,758	40,580	47,963	55,637	62,793	74,955	74,955	86,528	86,866	87,268	102,110	69,140
3921	TRANSP EQUIP-CARS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3922	TRANS-LIGHT TRUCK, VAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
397	COMMUNICATION EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
398	MISCELLANEOUS EQUIPMENT	-	-	-	-	-	-	-	-	-	778	10,556	10,556	10,556	2,496
399	TANGIBLE PROPERTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	304,476	338,007	345,403	319,434	283,301	180,933	99,026	119,825	124,777	161,307	207,479	237,531	287,561	231,467

(1) 1070	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
	ALLOCATED TO NATURAL GAS - AFUDC NOT CHARGED - SEE BELOW FOR ALLOCATION PERCENTAGES														
303	MISC. INTANGIBLE PLANT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
390	STRUCTURES AND IMPROVEMENTS	7,191	24,450	24,972	24,441	-	-	2,841	14,389	16,924	36,230	55,700	67,163	82,475	27,444
3911	OFFICE FURNITURE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3912	OFFICE MACHINES	-	-	-	-	-	-	-	-	-	-	-	4,308	4,308	663
3913	E D P EQUIPMENT	120,878	121,695	123,449	121,468	122,376	65,154	16,105	9,476	9,611	3,593	3,593	3,824	7,377	56,046
391305	COMPUTER SOFTWARE	30,525	30,525	32,114	21,102	24,941	28,931	32,652	38,977	38,977	44,995	45,170	45,379	53,097	35,953
3921	TRANSP EQUIP-CARS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3922	TRANS-LIGHT TRUCK, VAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
397	COMMUNICATION EQUIPMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
398	MISCELLANEOUS EQUIPMENT	-	-	-	-	-	-	-	-	-	420	5,700	5,700	5,700	1,348
399	TANGIBLE PROPERTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	158,594	176,669	180,534	167,011	147,317	94,085	51,599	62,842	65,511	85,237	110,163	126,374	152,957	121,454

(1) 1070	(2) DESCRIPTION	(3) 13-MO AVG	(4) ALLOOCATE TO UTILITY ALLOC. %	(5) 13-MO AVG	(8) ALLOCATION METHOD
303	MISC. INTANGIBLE PLANT	-	54%	-	Consolidated Plant Less EDP & Software
389	LAND AND LAND RIGHTS	-	54%	-	Consolidated Plant Less EDP & Software
390	STRUCTURES AND IMPROVEMENTS	50,823	54%	27,444	Consolidated Plant Less EDP & Software
3911	OFFICE FURNITURE	-	54%	-	Consolidated Plant Less EDP & Software
3912	OFFICE MACHINES	1,227	54%	663	Consolidated Plant Less EDP & Software
3913	E D P EQUIPMENT	107,781	52%	56,046	Consolidated EDP & Software
391305	COMPUTER SOFTWARE	69,140	52%	35,953	Consolidated EDP & Software
3921	TRANSP EQUIP-CARS	-	54%	-	Consolidated Plant Less EDP & Software
3922	TRANS-LIGHT TRUCK, VAN	-	54%	-	Consolidated Plant Less EDP & Software
397	COMMUNICATION EQUIPMENT	-	54%	-	Consolidated Plant Less EDP & Software
398	MISCELLANEOUS EQUIPMENT	2,496	54%	1,348	Consolidated Plant Less EDP & Software
399	TANGIBLE PROPERTY	-	54%	-	Consolidated Plant Less EDP & Software
	TOTAL	231,467		121,454	

COMON. CWIP - AFUDC CHARGED
NONE- FPUC DOES NOT CHARGE AFUDC

COMON. CWIP - AFUDC CHARGED
NONE- FPUC DOES NOT CHARGE AFUDC

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, B-2, B-8 Page 1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE DEPRECIATION RESERVE BALANCES FOR EACH ACCOUNT OR SUB-ACCOUNT TO WHICH DEPRECIATION IS APPLIED TO THE AVERAGE MONTHLY BALANCE

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

	(1) Acct 1080	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
1		INTANGIBLE PLANT														
2	303	MISC. INTANGIBLE PLANT	(96,182)	(96,787)	(97,392)	(97,997)	(98,602)	(99,207)	(99,812)	(100,417)	(101,022)	(101,627)	(102,232)	(102,837)	(103,442)	(99,812)
3	3031	INTANGIBLE NON-COMPETE AGREEMENT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4		TOTAL INTANGIBLE PLANT	(96,182)	(96,787)	(97,392)	(97,997)	(98,602)	(99,207)	(99,812)	(100,417)	(101,022)	(101,627)	(102,232)	(102,837)	(103,442)	(99,812)
6		DISTRIBUTION PLANT														
7	374	LAND	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	3741	LAND RIGHTS	8,076	8,042	8,008	7,974	7,940	7,906	7,872	7,838	7,804	7,770	7,736	7,702	7,668	7,872
9	375	STRUCTURES AND IMPROVEMENTS	(240,056)	(241,169)	(242,282)	(243,395)	(244,508)	(245,621)	(246,734)	(247,847)	(248,960)	(250,073)	(251,186)	(252,299)	(253,412)	(246,734)
10	3761	MAINS- PLASTIC	(3,972,067)	(4,019,412)	(4,066,601)	(4,090,490)	(4,140,328)	(4,188,835)	(4,237,788)	(4,287,968)	(4,338,862)	(4,322,553)	(4,370,926)	(4,420,674)	(4,549,881)	(4,231,260)
11	3762	MAINS -OTHER-(CAST IRON, STEEL)	(13,689,227)	(13,742,795)	(13,796,953)	(13,842,838)	(13,893,117)	(13,945,330)	(14,001,187)	(14,052,056)	(14,105,879)	(14,163,121)	(14,220,220)	(14,258,657)	(14,262,057)	(13,997,957)
12	378	MEASURE/REGULATOR EQP.-GENERAL	(79,706)	(80,574)	(81,442)	(82,310)	(83,178)	(84,046)	(84,914)	(85,782)	(86,650)	(87,518)	(88,386)	(89,254)	(90,091)	(84,912)
13	379	MEASURE/REG EQP - CITY GATE STN	(401,456)	(407,330)	(413,204)	(419,078)	(424,952)	(430,826)	(436,700)	(442,574)	(448,448)	(454,322)	(460,196)	(466,070)	(470,614)	(436,598)
14	3801	SERVICES - PLASTIC	(4,937,741)	(4,987,230)	(5,035,934)	(5,062,719)	(5,104,500)	(5,145,629)	(5,189,920)	(5,229,731)	(5,264,276)	(5,305,229)	(5,342,226)	(5,386,287)	(5,433,162)	(5,186,506)
15	3802	SERVICES - OTHER- CAST IRON, ETC	(1,867,030)	(1,870,491)	(1,875,597)	(1,870,688)	(1,869,126)	(1,866,204)	(1,866,445)	(1,869,375)	(1,870,724)	(1,872,086)	(1,871,253)	(1,864,186)	(1,870,080)	(1,869,483)
17	381	METERS	(2,005,060)	(2,020,250)	(2,035,580)	(2,048,869)	(2,058,206)	(2,073,457)	(2,063,607)	(2,072,721)	(2,088,004)	(2,104,397)	(2,119,470)	(2,133,934)	(2,149,101)	(2,074,820)
18	382	METER INSTALLATIONS	(681,514)	(687,623)	(693,586)	(697,814)	(703,204)	(708,116)	(714,117)	(720,064)	(725,571)	(732,172)	(737,504)	(743,924)	(751,390)	(715,123)
19	383	HOUSE REGULATORS	(676,159)	(681,221)	(686,283)	(690,134)	(693,945)	(699,230)	(702,682)	(707,591)	(711,631)	(716,646)	(722,268)	(727,667)	(732,099)	(703,658)
20	384	HOUSE REGULATOR INSTALLATIONS	(246,166)	(248,595)	(251,034)	(252,748)	(254,848)	(256,394)	(258,604)	(260,796)	(262,793)	(265,114)	(267,142)	(269,490)	(271,874)	(258,892)
21	385	INDUST MEASURING/REG STATION EQP	(11,283)	(11,416)	(11,549)	(11,682)	(12,811)	(11,948)	(12,081)	(12,214)	(12,347)	(12,480)	(12,613)	(12,746)	(12,882)	(12,158)
22	387	OTHER EQUIPMENT	(101,554)	(103,179)	(104,820)	(106,486)	(108,155)	(109,845)	(105,226)	(106,945)	(108,666)	(110,391)	(112,116)	(113,841)	(115,574)	(108,215)
23		TOTAL DISTRIBUTION PLANT	(28,900,943)	(29,093,243)	(29,286,857)	(29,411,277)	(29,582,938)	(29,757,575)	(29,912,133)	(30,087,826)	(30,265,007)	(30,388,332)	(30,567,770)	(30,731,327)	(30,954,549)	(29,918,444)
24		GENERAL PLANT														
25	389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	3892	RIGHTS-OF-WAY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	390	STRUCTURES AND IMPROVEMENTS	(305,873)	(308,778)	(311,683)	(314,588)	(317,503)	(320,418)	(323,333)	(326,248)	(329,168)	(332,120)	(321,656)	(324,581)	(327,506)	(320,266)
28	3911	OFFICE FURNITURE	(26,385)	(26,825)	(27,265)	(27,705)	(28,157)	(28,609)	(29,061)	(29,513)	(29,965)	(27,950)	(28,392)	(28,834)	(29,276)	(28,303)
29	3912	OFFICE MACHINES	(22,142)	(22,389)	(22,636)	(22,883)	(23,176)	(23,469)	(23,762)	(24,055)	(24,348)	(24,641)	(30,482)	(30,897)	(31,312)	(25,092)
30	3913	E D P EQUIPMENT	(43,030)	(48,404)	(53,778)	(55,356)	(59,090)	(62,913)	(59,979)	(55,456)	(60,555)	(62,948)	(65,808)	(74,464)	(80,151)	(60,149)
31	391305	COMPUTER SOFTWARE	(34,828)	(39,309)	(43,790)	(48,287)	(52,784)	(57,623)	(62,517)	(67,411)	(72,305)	(77,199)	(82,093)	(86,987)	(91,881)	(62,847)
32	3921	TRANSP EQUIP-CARS	(56,442)	(58,895)	(60,572)	(62,249)	(63,926)	(65,603)	(67,280)	(72,112)	(73,956)	(75,800)	(77,644)	(8,576)	(25,740)	(59,138)
33	3922	TRANS - LIGHT TRUCK, VAN	(851,194)	(874,027)	(896,860)	(919,693)	(942,526)	(965,375)	(988,241)	(1,011,107)	(1,033,973)	(1,056,839)	(1,079,900)	(885,535)	(925,232)	(956,192)
34	3923	TRANS - HEAVY TRUCKS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	3924	TRANS - TRAILERS	(25,308)	(25,518)	(25,728)	(25,938)	(26,148)	(26,558)	(26,771)	(26,984)	(27,197)	(27,410)	(27,641)	(26,159)	(26,376)	(26,441)
36	393	STORES EQUIPMENT	(8,915)	(8,952)	(8,989)	(9,026)	(9,063)	(9,100)	(9,137)	(9,174)	(9,211)	(9,248)	(9,285)	(9,322)	(9,359)	(9,137)
37	394	TOOLS, SHOP & GARAGE EQUIPMENT	(155,065)	(156,682)	(158,241)	(159,800)	(158,206)	(159,851)	(161,547)	(163,243)	(164,947)	(158,319)	(159,990)	(160,161)	(162,370)	(159,879)
38	396	POWER OPERATED EQUIPMENT	(105,372)	(107,094)	(108,816)	(110,538)	(112,260)	(113,982)	(115,704)	(117,426)	(119,174)	(120,922)	(122,670)	(117,283)	(118,976)	(114,632)
39	397	COMMUNICATION	(120,599)	(122,351)	(124,103)	(125,855)	(127,607)	(129,359)	(131,111)	(132,863)	(134,623)	(136,383)	(138,143)	(91,759)	(93,254)	(123,693)
40	398	MISCELLANEOUS EQUIPMENT	(10,269)	(10,992)	(11,715)	(12,438)	(13,161)	(13,884)	(14,607)	(15,330)	(16,053)	(16,776)	(12,952)	(13,702)	(14,638)	(13,578)
41	399	TANGIBLE PROPERTY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42		TOTAL GENERAL PLANT	(1,765,422)	(1,810,216)	(1,854,176)	(1,894,356)	(1,933,607)	(1,976,744)	(2,013,050)	(2,050,922)	(2,095,475)	(2,126,555)	(2,156,656)	(1,858,260)	(1,936,071)	(1,959,347)
43																
44		TOTAL UTILITY PLANT	(30,762,547)	(31,000,246)	(31,238,425)	(31,403,630)	(31,615,147)	(31,833,526)	(32,024,995)	(32,239,165)	(32,461,504)	(32,616,514)	(32,826,658)	(32,692,424)	(32,994,062)	(31,977,603)
45																

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-2, B-5, B-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:PROVIDE THE AMORTIZATION/RECOVERY RESERVE BALANCES FOR EACH ACCOUNT OR SUB-ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

LINE NO.	A/C NO.	DESCRIPTION	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	13 MONTH AVERAGE
1	1820.3	REG ASSET - ENVRNMTL PEND	$ 8,270,704	8,232,675	8,194,646	8,107,517	8,069,488	8,031,459	7,955,630	7,917,601	7,879,572	7,812,143	7,774,114	7,736,085	7,652,656	7,971,868
2																
3	2530.31	ENVIRON COSTS NET OF CUSTOMER PROCEEDS	(149,051)	(187,361)	(215,821)	(237,880)	(275,842)	(306,804)	(332,194)	(363,178)	(396,208)	(410,428)	(449,275)	(470,929)	(481,863)	(328,987)
4																
5	2530.32	ENVIRONMENTAL LIABILITY PENDING RATE RECOVERY	(8,270,704)	(8,232,675)	(8,194,646)	(8,107,517)	(8,069,488)	(8,031,459)	(7,955,630)	(7,917,601)	(7,879,572)	(7,812,143)	(7,774,114)	(7,736,085)	(7,652,656)	(7,971,868)
6																
7																
8																
9																
10																
11																
12		TOTAL	$ (149,051)	(187,361)	(215,821)	(237,880)	(275,842)	(306,804)	(332,194)	(363,178)	(396,208)	(410,428)	(449,275)	(470,929)	(481,863)	(328,987)
13																
14																

LINE NO.	S.J. No.	DESCRIPTION	A TOTAL LIABILITY	B TOTAL CHARGES	C AMORTIZATION :UST PROCEED	D B + C COSTS LESS PROCEEDS
20	3500	Manufactured Gas Plant Site - Sanford	630,570	1,137,637	n/a	n/a
21						
22	3510	Manufactured Gas Plant Site - Deland		10,244	n/a	n/a
23						
24	3590	Manufactured Gas Plant Site - Pensacola	40,000	122,850	n/a	n/a
25						
26	3600	Manufactured Gas Plant Site - Key West	93,003	38,170	n/a	n/a
27						
28	3690	Manufactured Gas Plant Site Litigation - Sanford	723,623	146,435	n/a	n/a
29						
30	3730	Manufactured Gas Plant Insurance Carrier-Sanford	420,376	349,287	n/a	n/a
31						
32	3760	Manufactured Gas Plant Site - West Palm Beach	12,092,800	1,478,559	n/a	n/a
33						
34						
35		TOTALS	$ 14,000,372	3,283,182	(3,765,044)	(481,862)
36						
37						
38						
39						

LINE NO.	A/C NO.	DESCRIPTION	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	13 MONTH AVERAGE
40	1860.4	OTHER DEFERRED DEBITS-AEP	3,952,092	3,920,408	3,930,427	3,889,511	3,864,733	3,862,734	3,852,283	3,848,601	3,873,294	3,901,668	4,252,148	4,246,990	4,264,682	3,973,813
41																
42	1150.1	ACQUISITION ADJUSTMENT - RESERVE	(374,686)	(377,274)	(379,862)	(382,451)	(385,039)	(387,627)	(390,216)	(392,804)	(395,676)	(397,981)	(400,569)	(403,157)	(405,746)	(390,238)
43																
44	2530.4	UNAMORTIZED GAINS	(40,653)	(30,618)	(20,583)	(10,548)	(7,911)	(5,274)	(2,637)	0	0	0	0	0	0	(9,094)
45																

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, B-3, B-13

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE SHOWING THE SAME DATA AS REQUIRED IN SCHEDULE B-5 FOR DEPRECIATION/RESERVE BALANCES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

	(1) Acct 1190	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
1	303	MISC. INTANGIBLE PLANT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	390	STRUCTURES AND IMPROVEMENTS	(429,446)	(433,850)	(438,256)	(442,662)	(443,302)	(447,807)	(452,312)	(456,817)	(461,322)	(465,833)	(470,351)	(474,869)	(479,391)	(453,555)
4	3911	OFFICE FURNITURE	(10,739)	(10,891)	(11,043)	(11,195)	(11,347)	(11,499)	(11,651)	(11,803)	(11,955)	(12,107)	(12,259)	(12,411)	(12,563)	(11,651)
5	3912	OFFICE MACHINES	(34,578)	(35,468)	(36,358)	(37,248)	(38,138)	(38,076)	(38,960)	(39,859)	(40,758)	(41,657)	(37,025)	(37,818)	(38,611)	(38,043)
6	3913	E D P EQUIPMENT	(146,783)	(151,335)	(155,887)	(147,670)	(152,210)	(160,608)	(163,929)	(146,709)	(154,209)	(158,829)	(159,168)	(143,515)	(150,217)	(153,159)
7	391305	COMPUTER SOFTWARE	(1,112,156)	(1,128,039)	(1,143,922)	(1,159,812)	(1,176,023)	(1,192,234)	(1,208,456)	(1,224,696)	(1,240,936)	(1,257,237)	(1,273,538)	(1,289,839)	(1,306,140)	(1,208,694)
8	3921	TRANSP EQUIP-CARS	(31,562)	(32,354)	(33,146)	(33,938)	(34,730)	(35,522)	(36,314)	(37,106)	(37,898)	(38,690)	(39,482)	(40,274)	(41,066)	(36,314)
9	3922	TRANS-LIGHT TRUCK, VAN	(24,374)	(25,226)	(26,078)	(26,930)	(27,782)	(28,634)	(29,486)	(30,338)	(31,190)	(32,042)	(32,894)	(33,746)	(34,598)	(29,486)
10	397	COMMUNICATION EQUIPMENT	32,969	32,209	31,449	30,689	29,929	29,169	28,409	27,649	26,889	26,129	25,369	24,609	23,849	28,409
11	398	MISCELLANEOUS EQUIPMENT	(231)	(265)	(299)	(333)	(367)	(401)	(435)	(484)	(533)	(582)	(631)	(680)	(729)	(459)
12	399	TANGIBLE PROPERTY	(3,745)	(5,438)	(5,821)	(6,204)	(6,587)	(6,969)	(7,352)	(7,735)	(8,118)	(8,501)	(8,884)	(9,266)	(9,649)	(7,251)
13		TOTAL	(1,760,645)	(1,790,657)	(1,819,361)	(1,835,303)	(1,860,557)	(1,892,581)	(1,920,486)	(1,927,898)	(1,960,030)	(1,989,349)	(2,008,863)	(2,017,809)	(2,049,115)	(1,910,203)

	(1) Acct 1190	(2) DESCRIPTION	(3) DEC. '06	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) 13-MO AVG
		ALLOCATED TO NATURAL GAS - SEE BELOW FOR ALLOCATION PERCENTAGES														
1	303	MISC. INTANGIBLE PLANT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	389	LAND AND LAND RIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	390	STRUCTURES AND IMPROVEMENTS	(231,901)	(234,279)	(236,658)	(239,037)	(239,383)	(241,816)	(244,248)	(246,681)	(249,114)	(251,550)	(253,990)	(256,429)	(258,871)	(244,920)
4	3911	OFFICE FURNITURE	(5,799)	(5,881)	(5,963)	(6,045)	(6,127)	(6,209)	(6,292)	(6,374)	(6,456)	(6,538)	(6,620)	(6,702)	(6,784)	(6,292)
5	3912	OFFICE MACHINES	(18,672)	(19,153)	(19,633)	(20,114)	(20,595)	(20,561)	(21,038)	(21,524)	(22,009)	(22,495)	(19,994)	(20,422)	(20,850)	(20,543)
6	3913	E D P EQUIPMENT	(76,327)	(78,694)	(81,061)	(76,788)	(79,149)	(83,516)	(85,243)	(76,289)	(80,189)	(82,591)	(82,767)	(74,628)	(78,113)	(79,643)
7	391305	COMPUTER SOFTWARE	(578,321)	(586,580)	(594,839)	(603,102)	(611,532)	(619,962)	(628,397)	(636,842)	(645,287)	(653,763)	(662,240)	(670,716)	(679,193)	(628,521)
8	3921	TRANSP EQUIP-CARS	(17,043)	(17,471)	(17,899)	(18,327)	(18,754)	(19,182)	(19,610)	(20,037)	(20,465)	(20,893)	(21,320)	(21,748)	(22,176)	(19,610)
9	3922	TRANS-LIGHT TRUCK, VAN	(13,162)	(13,622)	(14,082)	(14,542)	(15,002)	(15,462)	(15,922)	(16,383)	(16,843)	(17,303)	(17,763)	(18,223)	(18,683)	(15,922)
10	397	COMMUNICATION EQUIPMENT	17,803	17,393	16,982	16,572	16,162	15,751	15,341	14,930	14,520	14,110	13,699	13,289	12,878	15,341
11	398	MISCELLANEOUS EQUIPMENT	(125)	(143)	(161)	(180)	(198)	(217)	(235)	(261)	(288)	(314)	(341)	(367)	(394)	(248)
12	399	TANGIBLE PROPERTY	(2,022)	(2,937)	(3,143)	(3,350)	(3,557)	(3,763)	(3,970)	(4,177)	(4,384)	(4,591)	(4,797)	(5,004)	(5,210)	(3,916)
13		TOTAL	(925,570)	(941,367)	(956,459)	(964,914)	(978,136)	(994,937)	(1,009,615)	(1,013,637)	(1,030,513)	(1,045,927)	(1,056,132)	(1,060,950)	(1,077,395)	(1,004,274)

	(1) Acct 1190	(2) DESCRIPTION	(3) 13-MO AVG	(4) ALLOOCATE TO UTILITY ALLOC. %	(5) ALLOOCATE TO UTILITY 13-MO AVG	(6) NON-UTILITY ALLOC. %	(7) NON-UTILITY 13-MO AVG	(8) ALLOCATION METHOD
1	303	MISC. INTANGIBLE PLANT	-	54%	-	46%	-	Consolidated Plant Less EDP & Software
2	389	LAND AND LAND RIGHTS	-	54%	-	46%	-	Consolidated Plant Less EDP & Software
3	390	STRUCTURES AND IMPROVEMENTS	(453,555)	54%	(244,920)	46%	(208,635)	Consolidated Plant Less EDP & Software
4	3911	OFFICE FURNITURE	(11,651)	54%	(6,292)	46%	(5,359)	Consolidated Plant Less EDP & Software
5	3912	OFFICE MACHINES	(38,043)	54%	(20,543)	46%	(17,500)	Consolidated Plant Less EDP & Software
6	3913	E D P EQUIPMENT	(153,159)	52%	(79,643)	48%	(73,516)	Consolidated EDP & Software
7	391305	COMPUTER SOFTWARE	(1,208,694)	52%	(628,522)	48%	(580,172)	Consolidated EDP & Software
8	3921	TRANSP EQUIP-CARS	(36,314)	54%	(19,610)	46%	(16,704)	Consolidated Plant Less EDP & Software
9	3922	TRANS-LIGHT TRUCK, VAN	(29,486)	54%	(15,922)	46%	(13,564)	Consolidated Plant Less EDP & Software
10	397	COMMUNICATION EQUIPMENT	28,409	54%	15,341	46%	13,068	Consolidated Plant Less EDP & Software
11	398	MISCELLANEOUS EQUIPMENT	(459)	54%	(248)	46%	(211)	Consolidated Plant Less EDP & Software
12	399	TANGIBLE PROPERTY	(7,251)	54%	(3,916)	46%	(3,335)	Consolidated Plant Less EDP & Software
13		TOTAL	(1,910,203)		(1,004,274)		(905,929)	

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1

SCHEDULE B-12	**CUSTOMER ADVANCES FOR CONSTRUCTION**	PAGE 1 OF 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	CUSTOMER ADVANCES FOR CONSTRUCTION FOR THE 13-MONTH PERIOD ENDING WITH THE LAST MONTH OF THE HISTORIC BASE YEAR. **ACCOUNT 2520**	TYPE OF DATA SHOWN: HISTORIC BASE YEAR: 12/31/2007 WITNESS: MESITE

LINE NO.	MONTH	AMOUNT
1	Dec-06	(1,413,893)
2	Jan-07	(1,422,511)
3	Feb-07	(1,435,745)
4	Mar-07	(1,462,728)
5	Apr-07	(1,544,269)
6	May-07	(1,552,302)
7	Jun-07	(1,668,155)
8	Jul-07	(1,660,557)
9	Aug-07	(1,677,568)
10	Sep-07	(1,673,738)
11	Oct-07	(1,785,010)
12	Nov-07	(1,816,594)
13	Dec-07	(1,883,514)
14	12 MONTH TOTAL	(19,582,691)
15	13 MONTH AVERAGE	(1,615,122)

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE WORKING CAPITAL ALLOWANCE FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN: HISTORIC YEAR ENDED 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) UTILITY 13-MO AVG	(6) REFERENCE	(7) UNADJUSTED WORKING CAPITAL	(8) <<<<< ADJUSTMENTS >>>>> CAPITAL STRUCTURE	(9) PLANT	(10) NON-UTILITY	(11) << WORKING CAPITAL ADJUSTMENTS >> AMOUNT	(12) DESCRIPTION	(13) ALLOCATION PERCENTAGE	(14) ADJUSTED AVERAGE WORKING CAPITAL
1			ASSETS										
2			PLANT										
3	1010		PLANT-IN-SERVICE - GAS	97,425,925	RATE BASE			(97,425,925)					-
4	1180		PLANT-IN-SERVICE - COMMON	2,888,025	RATE BASE			(2,888,025)					-
5	1070		CWIP - GAS	2,835,241	RATE BASE			(2,835,241)					-
6	1070		CWIP - COMMON	121,454	RATE BASE			(121,454)					-
7	1140		ACQUISITION ADJ. (GROSS)	1,816,579	RATE BASE			(1,816,579)					-
8			GROSS UTILITY PLANT	105,087,224		-	-	(105,087,224)	-	-			-
9			RESERVE										
10	1080		PLANT RESERVE - GAS	(31,977,603)	RATE BASE			31,977,603					-
11	1190		PLANT RESERVE - COMMON	(1,004,273)	RATE BASE			1,004,273					-
12	1150		ACQUISITION ADJ. - RESERVE	(390,238)	RATE BASE			390,238					-
13			TOTAL RESERVES	(33,372,114)		-	-	33,372,114	-	-			-
14			NET PLANT	71,715,110		-	-	(71,715,110)	-	-			-
15			OTHER PROPERTY AND INVESTMENTS										
16	1210		NON-UTILITY PROPERTY	8,436	WORKING CAPITAL	8,436							8,436
17	1280		OTHER FUNDS	5,100	WORKING CAPITAL	5,100							5,100
18			TOTAL	13,536		13,536	-	-	-	-			13,536
19			CURRENT AND ACCRUED ASSETS										
20	1310		CASH	430,686	WORKING CAPITAL	430,686							430,686
21	1350		WORKING FUNDS / PETTY CASH	25,206	WORKING CAPITAL	25,206							25,206
22	1350	10	FUNDS-PETTY CASH, ALLOC.	260	WORKING CAPITAL	260							260
23	1420		ACCTS REC - CUSTOMERS	4,557,012	WORKING CAPITAL	4,557,012							4,557,012
24	1430		ACCOUNTS RECEIVABLE - OTHER	54,266	WORKING CAPITAL	54,266							54,266
25	1440		ALLOW. FOR UNCOLLECTABLE	(219,801)	WORKING CAPITAL	(219,801)							(219,801)
26	1540		MATERIALS & SUPPLIES INV.	496,530	WORKING CAPITAL	496,530				(44,688)	Non-regulated Inventory	9%	451,842
27	1630		PPD STORES EXPENSE	1,095	WORKING CAPITAL	1,095							1,095
28	1650	2, 5	PPD INSURANCE	289,370	WORKING CAPITAL	289,370							289,370
29	1650	4	PPD MISCELLANEOUS	60,993	WORKING CAPITAL	60,993							60,993
30	1650	41	PPD ORCOM MAINTENANCE	29,999	WORKING CAPITAL	29,999							29,999
31	1730		UNBILLED REVENUES	926,761	WORKING CAPITAL	926,761							926,761
32													
33			TOTAL	6,652,377		6,652,377	-	-	-	(44,688)			6,607,689
34			DEFERRED DEBITS										
35	1810	1	UNAMORT DEBT DISCOUNT	933,534	CAPITAL STRUCTURE		(933,534)						-
36	1820	2	REG ASSET - RETIREMENT PL	175,817	WORKING CAPITAL	175,817							175,817
37	1820	3	REG ASSET - ENVRNMTL PEND	7,971,868	WORKING CAPITAL	7,971,868							7,971,868
38	1820	3n	REG ASSET - STORM RESERVE	146,061	WORKING CAPITAL	146,061							146,061
39	1840	1	CLEARING - NG	375	WORKING CAPITAL	375							375
40	1840	1	CLEARING - ALLOCATED	13	WORKING CAPITAL	13							13
41	1860	1	UNAMORTIZED RATE CASE-NG	132,945	WORKING CAPITAL	132,945				(66,473)	1/2 Excluded From Working Capital	50%	66,472
42	1860	1	DEFERRED DR - NG	73,619	WORKING CAPITAL	73,619							73,619
43	1860	23	DEFERRED DR - PENNY ELIM	(38)	WORKING CAPITAL	(38)							(38)
44	1860	4	OTHER DEFERRED DEBITS - AEP	3,973,813	WORKING CAPITAL	3,973,813				(3,973,813)	Excluded From Working Capital	100%	-
45	1860	21, 61	UNDERREC - PGA & CONSERV	-	WORKING CAPITAL	-							-
46	1860	3	DEF DR - UNDIST CAPITAL PAYRL	24,143	WORKING CAPITAL	24,143							24,143
47	1860	3n	DEF PIPING & CONVERSION	1,426,167	WORKING CAPITAL	1,426,167							1,426,167
48	1890	1	UNAMORT LOSS ON REACCQU	105,973	CAPITAL STRUCTURE		(105,973)						-
49	1900		DEFERRED TAXES - DIRECT	3,264,256	CAPITAL STRUCTURE		(3,264,256)						-
50			TOTAL	18,228,546		13,924,783	(4,303,763)	-	-	(4,040,286)			9,884,497
51			TOTAL ASSETS	96,609,569		20,590,696	(4,303,763)	(71,715,110)	-	(4,084,974)			16,505,722

SUPPORTING SCHEDULES: B-1, B-3

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE CALCULATING THE 13-MONTH AVERAGE WORKING CAPITAL ALLOWANCE FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN: HISTORIC YEAR ENDED- 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1)	(2) ACCT	(3) SUB	(4) DESCRIPTION	(5) UTILITY 13-MO AVG	(6) REFERENCE	(7) UNADJUSTED WORKING CAPITAL	(8) <<<<< ADJUSTMENTS >>>>> CAPITAL STRUCTURE	(9) PLANT	(10) NON-UTILITY	(11) << WORKING CAPITAL ADJUSTMENTS >> AMOUNT	(12) DESCRIPTION	(13) ALLOCATION PERCENTAGE	(14) ADJUSTED AVERAGE WORKING CAPITAL
1			CAPITALIZATION & LIABILITIES										
2			PROPRIETARY CAPITAL										
3	2010	1	COMMON STOCK ISSUED	(4,918,811)	CAPITAL STRUCTURE		4,918,811						-
4	2040	1	PREFERRED STOCK ISSUED - $1	(318,559)	CAPITAL STRUCTURE		318,559						-
5	2070	1	PREMIUM ON COMMON STOCK	(2,998,447)	CAPITAL STRUCTURE		2,998,447						-
6	2110	1	MISC. PAID IN CAPITAL	(433,274)	CAPITAL STRUCTURE		433,274						-
7	2140	1	CAPITAL STOCK EXPENSE	227,473	CAPITAL STRUCTURE		(227,473)						-
8	2160	1	UNAPPROP RETAINED EARNINGS	(18,569,991)	CAPITAL STRUCTURE		18,569,991						-
9	2170	1	COMMON STOCK REAQUIRED	1,305,938	CAPITAL STRUCTURE		(1,305,938)						-
10			TOTAL	(25,705,671)		-	25,705,671	-	-	-			-
11			LONG-TERM DEBT										
12	2210	1	BONDS	(27,870,641)	CAPITAL STRUCTURE		27,870,641						-
13													
14			OTHER NON-CURRENT LIABILITIES										
15	2280	12	GAS STORM RESERVE	(188,130)	WORKING CAPITAL	(188,130)							(188,130)
16	2280	31	PENSION RESERVE	(1,767,973)	WORKING CAPITAL	(1,563,977)							(1,563,977)
17	2280	32	MEDICAL - POST RETIREMENT	(967,092)	WORKING CAPITAL	(967,092)							(967,092)
18	2280	34	401(K) ACCRUAL - COMPANY SHARE	(167)	WORKING CAPITAL	(148)							(148)
19	2280	201	ACCRUED LIABILITY INSURANCE	(72,494)	WORKING CAPITAL	(72,494)							(72,494)
20	2290	1	ACCUM PROV - RATE REFUNDS	(505,467)	WORKING CAPITAL	(505,467)				505,467	Excluded From Working Capital	100%	-
21			0	(3,501,323)		(3,297,308)	-	-	-	505,467			(2,791,841)
22			CURRENT AND ACCRUED LIABILITIES										
23	2310	1	NOTES PAYABLE	(2,389,274)	CAPITAL STRUCTURE		2,389,274						-
24	2320		ACCOUNTS PAYABLE - FUEL	(2,798,150)	WORKING CAPITAL	(2,798,150)							(2,798,150)
25	2320		ACCTS PAY -TRADE, NET OF FUEL	(1,290,366)	WORKING CAPITAL	(1,290,366)							(1,290,366)
26	2320		ACCOUNTS PAYABLE - OTHER	(424,544)	WORKING CAPITAL	(424,544)							(424,544)
27	2350	1	CUSTOMER DEPOSITS	(5,627,678)	CAPITAL STRUCTURE		5,627,678						-
28	2360	1	ACC'D PROPERTY TAXES	(402,401)	WORKING CAPITAL	(402,401)							(402,401)
29	2360	2, 3	FLA GROSS REC & FPSC ASSESS TAX	(249,340)	WORKING CAPITAL	(249,340)							(249,340)
30	2360	5, 6	ACC'D PAYROLL TAXES - F & S UNEMP.	(3,239)	WORKING CAPITAL	(3,239)							(3,239)
31	2360	8, 9	ACC'D INCOME TAXES	(1,119,508)	WORKING CAPITAL	(1,119,508)							(1,119,508)
32	2370	1, 2	ACC'D INTEREST - NOTES	(361,289)	WORKING CAPITAL	(361,289)							(361,289)
33	2370	3	ACC'D INTEREST- CUSTOM DEPOSITS	(181,578)	WORKING CAPITAL	(181,578)							(181,578)
34	2380		DIVIDENDS PAY - PREFERRED STOCK	(1,118)	WORKING CAPITAL	(1,118)							(1,118)
35	2410	2, 3	TAXES PAYABLE - EMPLOYEE W/H	7	WORKING CAPITAL	7							7
36	2410	6	TAXES PAYABLE - SALES	(41,637)	WORKING CAPITAL	(41,637)							(41,637)
37	2410		TAXES PAYABLE - FRANCH & MUNIPLE	(374,886)	WORKING CAPITAL	(374,886)							(374,886)
38	2420	7	VENDING FUND	(14,967)	WORKING CAPITAL	(14,967)							(14,967)
39	2420		ACCRUED OUTSIDE LEGAL AND AUDIT	(102,743)	WORKING CAPITAL	(102,743)							(102,743)
40	2420		MISC CURRENT ACCRUED LIABILITIES	(14,768)	WORKING CAPITAL	(14,768)							(14,768)
41	2420	1	ACCRUED VACATION	(627,673)	WORKING CAPITAL	(627,673)							(627,673)
42			TOTAL	(16,025,152)		(8,008,200)	8,016,952	-	-	-			(8,008,200)
43			DEFERRED CREDITS										
44	2520		CUSTOMER ADVANCES FOR CONSTR	(1,615,122)	RATE BASE			1,615,122					-
45	2530	31	ENVIRONMENTAL COSTS - NET OF CUSTOMER PROCEEDS	(328,987)	WORKING CAPITAL	(328,987)							(328,987)
46	2530	32	ENVIRONMENTAL LIABILITY - PENDING RATE RECOVERY	(7,971,868)	WORKING CAPITAL	(7,971,868)							(7,971,868)
47	2530		OVERRECOVERIES - CONSERV & PGA	(3,840,965)	WORKING CAPITAL	(3,840,965)							(3,840,965)
48	2530		DEFERRED CREDITS - MISC.	(9,078)	WORKING CAPITAL	(9,078)							(9,078)
49	2550		ITC	(190,499)	CAPITAL STRUCTURE		190,499						-
50	28nn		DEFERRED TAXES	(9,550,263)	CAPITAL STRUCTURE		9,550,263						-
51													
52			TOTAL	(23,506,782)		(12,150,898)	9,740,762	1,615,122	-	-			(12,150,898)
53			TOTAL CAPITALIZATION & LIABILITIES	(96,609,569)		(23,660,421)	71,334,026	1,615,122	-	505,467			(23,154,954)
54													
55			TOTAL ASSETS LESS CAPITALIZATION & LIABILITIES	-		(3,069,725)	67,030,263	(70,099,988)	-	(3,579,507)			(6,649,232)
56													
57			WORKING CAPITAL INCLUDED IN RATE BASE (SCHEDULE)			(3,069,725)				(3,579,507)			(6,649,232)

SUPPORTING SCHEDULES: B-1, B-3

RECAP SCHEDULES: B-2

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING A 13-MONTH AVERAGE DETAILED DESCRIPTION OF EACH TYPE OF ITEM INCLUDED IN MISCELLANEOUS DEFERRED DEBITS FOR THE HISTORIC BASE YEAR

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

Line NO.	Account No.	DESCRIPTION	Dec. '06	Jan. '07	Feb. '07	Mar. '07	Apr. '07	May. '07	Jun. '07	Jul. '07	Aug. '07	Sep. '07	Oct. '07	Nov. '07	Dec. '07	13 MONTH AVERAGE
1	1860.1	Natural Gas Rate Case	177,260	169,874	162,489	155,103	147,717	140,331	132,945	125,559	118,174	110,788	103,402	96,016	88,630	132,945
2																
3	1860.1	Central - Prepaid Charges - Commercial	(10,266)	(18,165)	(14,007)	(17,524)	(13,009)	(8,495)	(4,950)	(17,985)	(13,536)	(10,622)	(7,708)	(4,795)	(8,532)	(11,507)
4	1860.1	Odorant - Natural Gas	29,090	28,588	28,087	27,585	27,083	26,582	26,080	25,579	25,077	24,576	24,074	23,573	23,071	26,080
5	1860.1	Odorant - For Debary Gate Station	9,296	8,873	8,451	8,028	7,606	7,183	6,761	6,338	5,916	5,493	5,071	4,648	4,225	6,761
6	1860.1	Boynton Bch Gate Station	35,736	35,736	36,886	36,886	36,886	36,886	36,886	36,886	40,105	40,105	40,115	40,139	-	34,866
7	1860.1	Old Dixie Highway Purchase	77	1,100	-	-	-	-	-	-	-	-	-	-	-	91
8	1860.1	Water Tower Rd Purchase	0	76.91	1376.91	38031.21	39784.21	51439.08	128055.15	0	2932	406	189	189	0	20,191
9	1860.1	Property - Additional Debary	-	-	-	-	-	-	900	900	900	900	900	900	900	485
10	1860.1	Central Prepaid Charges - Rsidential	-	-	-	-	-	-	-	-	(17,253)	(10,501)	(7,876)	(5,251)	(2,625)	(3,347)
11		DEFERRED DR - NG (EXCL RATE CASE)	63,932	56,210	60,793	93,007	98,350	113,596	193,732	51,718	44,141	50,357	54,764	59,403	17,039	73,620
12																
13																
14	1860.23	DEFERRED DR - PENNY ELIM	-	(9)	(18)	(57)	(53)	(77)	(92)	(126)	(117)	(131)	(140)	(143)	-	(74)
15	1860.23	DEFERRED DR - PENNY ELIM: @ 51% UTILITY A	-	(5)	(9)	(29)	(27)	(39)	(47)	(64)	(60)	(67)	(71)	(73)	-	(38)
16																
17	1820.4	OTHER DEFERRED DEBITS - AEP	3,952,092	3,920,408	3,930,427	3,889,511	3,864,733	3,862,734	3,852,283	3,848,601	3,873,294	3,901,668	4,252,148	4,246,990	4,264,682	3,973,813
18																
19	1860.3	DEF DR - UNDIST CAPITAL PAYRL	-	19,998	19,766	37,122	40,282	63,488	-	13,562	28,725	32,071	53,334	-	5,509	24,143
20																
21	1860.3n	DEF PIPING & CONVERSION	1,520,645	1,485,583	1,459,176	1,423,506	1,415,893	1,396,035	1,406,731	1,428,344	1,414,467	1,424,610	1,414,495	1,381,294	1,369,395	1,426,167
22																
23		TOTAL (1, 11, 15, 17, 19, 21)	5,713,930	5,652,069	5,632,642	5,598,220	5,566,948	5,576,145	5,585,644	5,467,721	5,478,741	5,519,427	5,878,072	5,783,630	5,745,255	5,630,650

SUPPORTING SCHEDULES: RECAP SCHEDULES: B-1, B-13

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE SHOWING A 13-MONTH AVERAGE DETAILED DESCRIPTION OF EACH TYPE OF ITEM INCLUDED IN OTHER DEFERRED CREDITS FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

Line NO.	Account No.	DESCRIPTION	Dec. '06	Jan. '07	Feb. '07	Mar. '07	Apr. '07	May. '07	Jun. '07	Jul. '07	Aug. '07	Sep. '07	Oct. '07	Nov. '07	Dec. '07	13 MONTH AVERAGE
1	2530.1	DEFERRED CREDITS - CASHIERE O/S	-	(10)	5	4	48	73	91	101	105	98	(156)	(154)	-	16
2	2530.21	OVER RECOVER - FUEL	(3,656,021)	(3,968,881)	(3,399,409)	(3,420,031)	(3,423,439)	(3,700,039)	(3,818,729)	(3,669,921)	(3,644,206)	(3,463,353)	(3,268,487)	(2,131,162)	(1,378,279)	(3,303,227)
3	2530.31	ENVIRON COSTS NET OF CUSTOMER PROCEEDS	(149,051)	(187,361)	(215,821)	(237,880)	(275,842)	(306,804)	(332,194)	(363,178)	(396,208)	(410,428)	(449,275)	(470,929)	(481,863)	(328,987)
4	2530.32	ENVIRONMENTAL LIABILITY PENDING RATE RECOVERY	(8,270,704)	(8,232,675)	(8,194,646)	(8,107,517)	(8,069,488)	(8,031,459)	(7,955,630)	(7,917,601)	(7,879,572)	(7,812,143)	(7,774,114)	(7,736,085)	(7,652,656)	(7,971,868)
5	2530.4	UNAMORTIZED DEFERRED GAINS	(40,653)	(30,618)	(20,583)	(10,548)	(7,911)	(5,274)	(2,637)	-	-	-	-	-	-	(9,094)
6	2530.61	OVER RECOVERY - CONSERVATION	(310,673)	(488,742)	(639,100)	(731,227)	(662,757)	(692,890)	(587,966)	(607,698)	(551,533)	(491,805)	(395,204)	(402,399)	(428,585)	(537,737)
7		**Total Deferred Credits**	(12,427,102)	(12,908,287)	(12,469,554)	(12,507,199)	(12,439,389)	(12,736,393)	(12,697,065)	(12,558,297)	(12,471,414)	(12,177,631)	(11,887,236)	(10,740,729)	(9,941,383)	(12,150,897)

SUPPORTING SCHEDULES: RECAP SCHEDULES: B-1, B-13

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR ANY RATE BASE COMPONENT NOT ACCOUNTED FOR IN OTHER SCHEDULES, PROVIDE THE 13 MONTH AVERAGE BALANCE FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/07
WITNESS: MESITE

DESCRIPTION	13-MONTH AVERAGE	NON-UTILITY ALLOCATION FACTOR	NON-REGULATED AMOUNT	BASIS FOR ALLOCATION
Not Applicable				

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-2

SCHEDULE B-17	**INVESTMENT TAX CREDITS - ANALYSIS**	PAGE 1 OF 4
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	EXPLANATION: PROVIDE AN ANALYSIS OF ACCUMULATED TAX CREDITS GENERATED AND AMORTIZED ON AN ANNUAL BASIS BEGINNING WITH THE CURRENT HISTORIC BASE YEAR AND ON A MONTHLY BASIS FOR THE HISTORIC BASE YEAR. (EXCEPTION: ANNUAL DATA MAY BE SUBSTITUTED FOR MONTHLY DATA FOR THE 3% DEFERRED ITC). AMOUNTS PROVIDED BY THE REVENUE ACT OF 1971 AND SUBSEQUENT ACTS SHOULD BE SHOWN SEPARATELY FROM AMOUNTS APPLICABLE TO PRIOR LAWS. IDENTIFY PROGRESS PAYMENTS SEPARATELY.	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/07 WITNESS: MARTIN

			3% ITC						4% ITC					
				AMOUNT REALIZED		AMORTIZATION				AMOUNT REALIZED		AMORTIZATION		
LINE NO.	MONTH	YEAR	BEG. BALANCE	CURRENT YEAR	PRIOR YEAR ADJ.	CURRENT YEAR	PRIOR YEAR ADJ.	ENDING BALANCE	BEG. BALANCE	CURRENT YEAR	PRIOR YEAR ADJ.	CURRENT YEAR	PRIOR YEAR ADJ.	ENDING BALANCE
1.	DEC	1997	16,861.76			(4,088.69)		12,773.07	25,601.56			(3,300.25)		22,301.31
2.	DEC	1998	12,773.07			(4,088.69)		8,684.38	22,301.31			(3,300.25)		19,001.06
3.	DEC	1999	8,684.38			(3,781.77)		4,902.61	19,001.06			(3,300.25)		15,700.81
4.	DEC	2000	4,902.61			(2,231.20)		2,671.41	15,700.81			(2,654.71)		13,046.10
5.	DEC	2001	2,671.41			(1,512.47)		1,158.94	13,046.10			(2,654.71)		10,391.39
6.	DEC	2002	1,158.94			(926.76)		232.18	10,391.39			(2,654.71)		7,736.68
7.	DEC	2003	232.18			(226.23)		5.95	7,736.68			(2,654.71)		5,081.97
8.	DEC	2004	5.95			(5.95)		(0.00)	5,081.97			(2,577.70)		2,504.27
9.	DEC	2005	(0.00)			0.00		(0.00)	2,504.27			(2,026.89)		477.38
10.	DEC	2006	(0.00)			0.00		(0.00)	477.38			(474.67)		2.71
11.	JAN	2007	(0.00)			0.00		(0.00)	2.71			(0.23)		2.48
12.	FEB	2007	(0.00)			0.00		(0.00)	2.48			(0.23)		2.25
13.	MAR	2007	(0.00)			0.00		(0.00)	2.25			(0.23)		2.02
14.	APR	2007	(0.00)			0.00		(0.00)	2.02			(0.23)		1.79
15.	MAY	2007	(0.00)			0.00		(0.00)	1.79			(0.23)		1.56
16.	JUN	2007	(0.00)			0.00		(0.00)	1.56			(0.23)		1.33
17.	JUL	2007	(0.00)			0.00		(0.00)	1.33			(0.23)		1.10
18.	AUG	2007	(0.00)			0.00		(0.00)	1.10			(0.23)		0.87
19.	SEP	2007	(0.00)			0.00		(0.00)	0.87			(0.23)		0.64
20.	OCT	2007	(0.00)			0.00		(0.00)	0.64			(0.23)		0.41
21.	NOV	2007	(0.00)			0.00		(0.00)	0.41			(0.23)		0.18
22.	DEC	2007	(0.00)			0.00		(0.00)	0.18			(0.18)		0.00
13 MONTH AVERAGE								0.00						1.33
			TOTAL 13-MONTH AVERAGE PAGE 1 AND PAGE 2:					190,498.77						

SUPPORTING SCHEDULES: RECAP SCHEDULES: B-1, D-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE AN ANALYSIS OF ACCUMULATED TAX CREDITS GENERATED AND AMORTIZED ON AN ANNUAL BASIS BEGINNING WITH THE CURRENT HISTORIC BASE YEAR AND ON A MONTHLY BASIS FOR THE HISTORIC BASE YEAR. (EXCEPTION: ANNUAL DATA MAY BE SUBSTITUTED FOR MONTHLY DATA FOR THE 3% DEFERRED ITC). AMOUNTS PROVIDED BY THE REVENUE ACT OF 1971 AND SUBSEQUENT ACTS SHOULD BE SHOWN SEPARATELY FROM AMOUNTS APPLICABLE TO PRIOR LAWS. IDENTIFY PROGRESS PAYMENTS SEPARATELY.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

			8% ITC						10% ITC					
				AMOUNT REALIZED		AMORTIZATION				AMOUNT REALIZED		AMORTIZATION		
LINE NO.	MONTH	YEAR	BEG. BALANCE	CURRENT YEAR	PRIOR YEAR ADJ.	CURRENT YEAR	PRIOR YEAR ADJ.	ENDING BALANCE	BEG. BALANCE	CURRENT YEAR	PRIOR YEAR ADJ.	CURRENT YEAR	PRIOR YEAR ADJ.	ENDING BALANCE
1.	DEC	1997	56,663.20			(3,546.22)		53,116.98	573,320.87			(44,227.32)		529,093.55
2.	DEC	1998	53,116.98			(3,546.22)		49,570.76	529,093.55			(44,227.32)		484,866.23
3.	DEC	1999	49,570.76			(3,546.22)		46,024.54	484,866.23			(44,227.33)		440,638.90
4.	DEC	2000	46,024.54			(2,852.58)		43,171.96	440,638.90			(35,584.71)		405,054.19
5.	DEC	2001	43,171.96			(2,852.58)		40,319.38	405,054.19			(35,574.05)		369,480.14
6.	DEC	2002	40,319.38			(2,852.58)		37,466.80	369,480.14			(35,576.26)		333,903.88
7.	DEC	2003	37,466.80			(2,852.58)		34,614.22	333,903.88			(35,576.26)		298,327.62
8.	DEC	2004	34,614.22			(2,852.58)		31,761.64	298,327.62			(35,576.26)		262,751.36
9.	DEC	2005	31,761.64			(3,130.04)		28,631.60	262,751.36			(39,033.30)		223,718.06
10.	DEC	2006	28,631.60			(3,130.04)		25,501.56	223,718.06			(39,037.56)		184,680.50
11.	JAN	2007	25,501.56			(260.84)		25,240.72	184,680.50			(3,019.93)		181,660.57
12.	FEB	2007	25,240.72			(260.84)		24,979.88	181,660.57			(3,019.93)		178,640.64
13.	MAR	2007	24,979.88			(260.84)		24,719.04	178,640.64			(3,019.93)		175,620.71
14.	APR	2007	24,719.04			(260.84)		24,458.20	175,620.71			(3,019.93)		172,600.78
15.	MAY	2007	24,458.20			(260.84)		24,197.36	172,600.78			(3,019.93)		169,580.85
16.	JUN	2007	24,197.36			(260.84)		23,936.52	169,580.85			(3,019.93)		166,560.92
17.	JUL	2007	23,936.52			(260.84)		23,675.68	166,560.92			(3,019.93)		163,540.99
18.	AUG	2007	23,675.68			(260.84)		23,414.84	163,540.99			(3,019.93)		160,521.06
19.	SEP	2007	23,414.84			(260.84)		23,154.00	160,521.06			(3,019.93)		157,501.13
20.	OCT	2007	23,154.00			(260.84)		22,893.16	157,501.13			(3,019.93)		154,481.20
21.	NOV	2007	22,893.16			(260.84)		22,632.32	154,481.20			(3,019.93)		151,461.27
22.	DEC	2007	22,632.32			(260.84)		22,371.48	151,461.27			(3,019.88)		148,441.39
13 MONTH AVERAGE								23,936.52						166,560.92

SUPPORTING SCHEDULES: RECAP SCHEDULES: B-1, D-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE AN ANALYSIS OF ACCUMULATED TAX CREDITS GENERATED AND AMORTIZED ON AN ANNUAL BASIS BEGINNING WITH THE CURRENT HISTORIC BASE YEAR AND ON A MONTHLY BASIS FOR THE HISTORIC BASE YEAR. (EXCEPTION: ANNUAL DATA MAY BE SUBSTITUTED FOR MONTHLY DATA FOR THE 3% DEFERRED ITC). AMOUNTS PROVIDED BY THE REVENUE ACT OF 1971 AND SUBSEQUENT ACTS SHOULD BE SHOWN SEPARATELY FROM AMOUNTS APPLICABLE TO PRIOR LAWS. IDENTIFY PROGRESS PAYMENTS SEPARATELY.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED 12/31/07

WITNESS: MARTIN

ACCOUNTING POLICIES:

RATABLE AMORTIZATION IS BASED ON BOOK DEPRECIATION LIFE. DATA FROM PERIODIC DEPRECIATION STUDIES AS APPROVED BY THE FPSC. AMORTIZATION BEGINS THE CALENDAR YEAR FOLLOWING THE YEAR OF GENERATION.

THERE ARE NO CREDITS RELATED TO QUALIFIED PROGRESS PAYMENTS IN THE ACCUMULATED ITC BALANCES.

THERE ARE NO UNUSED ITC AVAILABLE.

THE COMPANY USES HALF YEAR CONVENTION IN THE YEAR PROPERTY IS PLACED IN SERVICE.

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, D-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE AN ANALYSIS OF ACCUMULATED TAX CREDITS GENERATED AND AMORTIZED ON AN ANNUAL BASIS BEGINNING WITH THE CURRENT HISTORIC BASE YEAR AND ON A MONTHLY BASIS FOR THE HISTORIC BASE YEAR. (EXCEPTION: ANNUAL DATA MAY BE SUBSTITUTED FOR MONTHLY DATA FOR THE 3% DEFERRED ITC). AMOUNTS PROVIDED BY THE REVENUE ACT OF 1971 AND SUBSEQUENT ACTS SHOULD BE SHOWN SEPARATELY FROM AMOUNTS APPLICABLE TO PRIOR LAWS. IDENTIFY PROGRESS PAYMENTS SEPARATELY.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED 12/31/07

WITNESS: MARTIN

COMPANY ELECTION UNDER SECTION 46(f) (2) (A) IRC:
COST OF SERVICE IS REDUCED BY A RATABLE PORTION OF THE CREDIT ALLOWED BY SECTION 38.

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, D-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR EACH OF THE ACCUMULATED DEFERRED INCOME TAX ACCOUNTS (NOS. 190, 281, 282, 283), PROVIDE ANNUAL BALANCES BEGINNING WITH THE HISTORIC BASE YEAR IN THE LAST RATE CASE AND ENDING WITH THE END OF THE TEST YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED 12/31/07
PRIOR YEARS ENDED 1997-2006

WITNESS: MARTIN

LINE			ACCOUNT 190			ACCOUNT 282			ACCOUNT 283			NET DEFERRED INCOME TAXES		
NO.	MONTH	YEAR	STATE	FEDERAL	TOTAL	STATE	FEDERAL	TOTAL	STATE	FEDERAL	TOTAL	STATE	FEDERAL	TOTAL
1.	DEC	1997	316,588	1,924,107	2,240,695	(577,194)	(4,108,177)	(4,685,371)	(24,224)	(141,502)	(165,726)	(284,830)	(2,325,572)	(2,610,402)
2.	DEC	1998	337,833	1,973,545	2,311,378	(589,078)	(4,165,343)	(4,754,421)	(29,920)	(174,794)	(204,714)	(281,165)	(2,366,592)	(2,647,757)
3.	DEC	1999	332,864	1,944,524	2,277,388	(644,642)	(4,427,348)	(5,071,990)	(83,069)	(485,277)	(568,346)	(394,847)	(2,968,101)	(3,362,948)
4.	DEC	2000	319,955	1,869,112	2,189,067	(661,725)	(4,482,906)	(5,144,631)	(113,202)	(661,295)	(774,497)	(454,972)	(3,275,089)	(3,730,061)
5.	DEC	2001	330,810	1,932,517	2,263,327	(688,438)	(4,630,158)	(5,318,596)	(57,406)	(334,478)	(391,884)	(415,034)	(3,032,119)	(3,447,153)
6.	DEC	2002	431,818	2,522,612	2,954,430	(740,895)	(4,910,502)	(5,651,397)	(101,784)	(593,726)	(695,510)	(410,861)	(2,981,616)	(3,392,477)
7.	DEC	2003	412,330	2,407,489	2,819,819	(927,858)	(5,063,306)	(5,991,164)	(147,062)	(433,558)	(580,620)	(662,590)	(3,089,375)	(3,751,965)
8.	DEC	2004	332,669	1,942,137	2,274,806	(1,110,865)	(6,159,024)	(7,269,889)	(42,931)	(250,796)	(293,727)	(821,127)	(4,467,683)	(5,288,810)
9.	DEC	2005	420,515	2,456,499	2,877,014	(1,358,427)	(7,625,957)	(8,984,384)	(153,952)	(899,364)	(1,053,316)	(1,091,864)	(6,068,822)	(7,160,686)
10.	DEC	2006	454,985	2,657,880	3,112,865	(1,490,900)	(9,120,980)	(10,611,880)	71,527	417,843	489,370	(964,388)	(6,045,257)	(7,009,645)
11.	JAN	2007	459,039	2,681,569	3,140,608	(1,629,533)	(8,954,561)	(10,584,094)	92,921	542,827	635,748	(1,077,573)	(5,730,165)	(6,807,738)
12.	FEB	2007	462,343	2,700,860	3,163,203	(1,624,356)	(8,924,319)	(10,548,675)	105,174	614,409	719,583	(1,056,839)	(5,609,050)	(6,665,889)
13.	MAR	2007	465,189	2,717,482	3,182,671	(1,622,412)	(8,912,967)	(10,535,379)	119,124	695,908	815,032	(1,038,099)	(5,499,577)	(6,537,676)
14.	APR	2007	467,686	2,732,067	3,199,753	(1,602,583)	(8,797,123)	(10,399,706)	114,286	667,643	781,929	(1,020,611)	(5,397,413)	(6,418,024)
15.	MAY	2007	470,904	2,750,858	3,221,762	(1,597,494)	(8,767,396)	(10,364,890)	121,561	710,140	831,701	(1,005,029)	(5,306,398)	(6,311,427)
16.	JUN	2007	480,610	2,807,640	3,288,250	(1,590,997)	(8,729,442)	(10,320,439)	114,719	670,163	784,882	(995,668)	(5,251,639)	(6,247,307)
17.	JUL	2007	484,397	2,829,762	3,314,159	(1,584,697)	(8,692,639)	(10,277,336)	121,422	709,319	830,741	(978,878)	(5,153,558)	(6,132,436)
18.	AUG	2007	487,051	2,845,264	3,332,315	(1,578,303)	(8,655,284)	(10,233,587)	114,873	671,071	785,944	(976,379)	(5,138,949)	(6,115,328)
19.	SEP	2007	488,341	2,852,794	3,341,135	(1,576,875)	(8,646,948)	(10,223,823)	109,304	638,541	747,845	(979,230)	(5,155,613)	(6,134,843)
20.	OCT	2007	493,835	2,884,884	3,378,719	(1,574,610)	(8,633,711)	(10,208,321)	109,475	639,532	749,007	(971,300)	(5,109,295)	(6,080,595)
21.	NOV	2007	494,245	2,887,286	3,381,531	(1,572,123)	(8,619,188)	(10,191,311)	115,353	673,872	789,225	(962,525)	(5,058,030)	(6,020,555)
22.	DEC	2007	493,783	2,884,601	3,378,384	(1,446,024)	(8,025,484)	(9,471,508)	125,189	731,342	856,531	(827,052)	(4,409,541)	(5,236,593)
13 MONTH AVERAGE			477,108	2,787,150	3,264,258	(1,576,224)	(8,729,234)	(10,305,458)	110,379	644,816	755,195	(988,736)	(5,297,268)	(6,286,004)

SUPPORTING SCHEDULES:

RECAP SCHEDULES: B-1, D-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR EACH OF THE ACCUMULATED DEFERRED INCOME TAX ACCOUNTS (NOS. 190, 281, 282, 283), PROVIDE ANNUAL BALANCES BEGINNING WITH THE HISTORIC BASE BASE YEAR IN THE LAST RATE CASE AND ENDING WITH THE END OF THE TEST YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED 12/31/07
PRIOR YEARS ENDED 1997-2006

WITNESS: MARTIN

LINE NO.	MONTH	YEAR	ACCOUNT 190 ENDING BALANCE	ACCOUNT 282 ENDING BALANCE	ACCOUNT 283 ENDING BALANCE
1.	DEC	1997	316,588	(577,194)	(24,224)
2.	DEC	1998	337,833	(589,078)	(29,920)
3.	DEC	1999	332,864	(644,642)	(83,069)
4.	DEC	2000	319,955	(661,725)	(113,202)
5.	DEC	2001	330,810	(688,438)	(57,406)
6.	DEC	2002	431,818	(740,895)	(101,784)
7.	DEC	2003	412,330	(927,858)	(147,062)
8.	DEC	2004	332,669	(1,110,865)	(42,931)
9.	DEC	2005	420,515	(1,358,427)	(153,952)
10.	DEC	2006	454,985	(1,490,900)	71,527
11.	JAN	2007	459,039	(1,629,533)	92,921
12.	FEB	2007	462,343	(1,624,356)	105,174
13.	MAR	2007	465,189	(1,622,412)	119,124
14.	APR	2007	467,686	(1,602,583)	114,286
15.	MAY	2007	470,904	(1,597,494)	121,561
16.	JUN	2007	480,610	(1,590,997)	114,719
17.	JUL	2007	484,397	(1,584,697)	121,422
18.	AUG	2007	487,051	(1,578,303)	114,873
19.	SEP	2007	488,341	(1,576,875)	109,304
20.	OCT	2007	493,835	(1,574,610)	109,475
21.	NOV	2007	494,245	(1,572,123)	115,353
22.	DEC	2007	493,783	(1,446,024)	125,189
13 MONTH AVERAGE			477,108	(1,576,224)	110,379

SUPPORTING SCHEDULES: | RECAP SCHEDULES:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR EACH OF THE ACCUMULATED DEFERRED INCOME TAX ACCOUNTS (NOS. 190, 281, 282, 283), PROVIDE ANNUAL BALANCES BEGINNING WITH THE HISTORIC BASE BASE YEAR IN THE LAST RATE CASE AND ENDING WITH THE END OF THE TEST YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED 12/31/07
PRIOR YEARS ENDED 1997-2006

WITNESS: MARTIN

LINE NO.	MONTH	YEAR	ACCOUNT 190 ENDING BALANCE	ACCOUNT 282 ENDING BALANCE	ACCOUNT 283 ENDING BALANCE
1.	DEC	1997	1,924,107	(4,108,177)	(141,502)
2.	DEC	1998	1,973,545	(4,165,343)	(174,794)
3.	DEC	1999	1,944,524	(4,427,348)	(485,277)
4.	DEC	2000	1,869,112	(4,482,906)	(661,295)
5.	DEC	2001	1,932,517	(4,630,158)	(334,478)
6.	DEC	2002	2,522,612	(4,910,502)	(593,726)
7.	DEC	2003	2,407,489	(5,063,306)	(433,558)
8.	DEC	2004	1,942,137	(6,159,024)	(250,796)
9.	DEC	2005	2,456,499	(7,625,957)	(899,364)
10.	DEC	2006	2,657,880	(9,120,980)	417,843
11.	JAN	2007	2,681,569	(8,954,561)	542,827
12.	FEB	2007	2,700,860	(8,924,319)	614,409
13.	MAR	2007	2,717,482	(8,912,967)	695,908
14.	APR	2007	2,732,067	(8,797,123)	667,643
15.	MAY	2007	2,750,858	(8,767,396)	710,140
16.	JUN	2007	2,807,640	(8,729,442)	670,163
17.	JUL	2007	2,829,762	(8,692,639)	709,319
18.	AUG	2007	2,845,264	(8,655,284)	671,071
19.	SEP	2007	2,852,794	(8,646,948)	638,541
20.	OCT	2007	2,884,884	(8,633,711)	639,532
21.	NOV	2007	2,887,286	(8,619,188)	673,872
22.	DEC	2007	2,884,601	(8,025,484)	731,342
13 MONTH AVERAGE			2,787,150	(8,729,234)	644,816

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080366-GU

MINIMUM FILING REQUIREMENTS
SCHEDULE C – NET OPERATING INCOME SCHEDULES

December 2008

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU
MINIMUM FILING REQUIREMENTS
INDEX: C SCHEDULES

NET OPERATING INCOME

SCHEDULE C-1 | ADJUSTED JURISDICTIONAL NET OPERATING INCOME |

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE CALCULATION OF JURISDICTIONAL NET OPERATING INCOME FOR THE HISTORIC YEAR ENDED AND THE PRIOR YEAR

TYPE OF DATA SHOWN:
PRIOR YEAR DATA: 12/31/2006
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

Line No.		(1) 2006 PRIOR YEAR TOTAL COMPANY PER BOOKS	(2) HISTORIC YEAR ENDED: 12/31/2007 TOTAL COMPANY PER BOOKS	(3) COMMISSION ADJUSTMENTS (SCHEDULE C-2)	(4) COMPANY ADJUSTMENTS (SCHEDULE C-2)	(5) ADJUSTED AMOUNT (5)+(6)+(7)
1	**OPERATING REVENUES**					
2	BASE REVENUES	23,958,812	23,744,649	-		23,744,649
3	FUEL	41,839,554	30,017,462	(30,017,462)		-
4	CONSERVATION	2,427,057	2,393,460	(2,393,460)		-
5	UNBUNDLING		-	-		-
6	GROSS RECEIPTS TAX	2,048,521	2,106,338	-		2,106,338
7	FRANCHISE TAX	1,626,446	1,533,487	-		1,533,487
8	OTHER OPERATING REVENUES	(761,058)	5,054,630	(2,707,492)		2,347,138
9						
10	TOTAL OPERATING REVENUES	71,139,332	64,850,026	(35,118,414)	-	29,731,612
11						
12	**OPERATING EXPENSES**					
13	OPERATION	13,756,028	14,217,572	24,621	-	14,242,193
14	MAINTENANCE	1,005,009	1,082,821	-	-	1,082,821
15	COST OF GAS	38,119,300	32,319,861	(32,319,861)	-	-
16	CONSERVATION	2,115,632	2,292,190	(2,292,190)	-	-
17	STORAGE & UNBUNDLING		6,070	-	-	6,070
18	DEPRECIATION	2,708,209	2,998,939	(108,001)	-	2,890,938
19	AMORTIZATION	1,591,194	1,568,494	(514,774)	-	1,053,720
20			-	-	-	-
21	TAXES OTHER THAN INCOME	5,726,043	5,716,755	(144,333)	-	5,572,422
22	INCOME TAX - FEDERAL & STATE	3,376,323	1,279,509	187,482	-	1,466,991
23					-	
24	DEFERRED I/T- FEDERAL & STATE	(1,997,258)	(494,988)	-	-	(494,988)
25						
26	INVESTMENT TAX CREDIT	(42,642)	(39,372)	-	-	(39,372)
27						
28						
29	TOTAL OPERATING EXPENSES	66,357,838	60,947,851	(35,167,056)	-	25,780,795
30						
31	NET OPERATING INCOME	4,781,494	3,902,175	48,642	-	3,950,817
32						
33						
34	RATE BASE	58,029,461	67,030,260	(7,511,287)		59,518,973
35						
36	RATE OF RETURN	8.24%	5.82%			6.64%

SUPPORTING SCHEDULES: C-2, C-3, C-5, C-17, C-18, C-19, C-20, C-21

RECAP SCHEDULES: F-4, F-5

Schedule C-2

JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF PROPOSED ADJUSTMENTS TO NET OPERATING JURISDICTIONAL COMPONENTS, AND THE REVENUE REQUIREMENT EFFECT ON EACH AND THE TOTAL. INDICATE WHICH ADJUSTMENTS WERE MADE IN THE COMPANY'S LAST FULL REVENUE REQUIREMENTS CASE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

Line No.	Adjustment	1 FUEL	2 CONS	3 OTHER	4 AEP	5 OOPOE	6 NON UTILITY	7 OOPCON	8 NON-UTILITY AMOUNT	9 Regulated Amount	10 TOTAL*	11 CHANGE IN REV REQ
												FACTOR 1.6233
1	**OPERATING REVENUES**											
2	BASE REVENUES	-	-	-	-	-	-	-	-	-	-	
3	FUEL	(30,017,462)	-	-	-	-	-	-	-	(30,017,462)	(30,017,462)	(48,727,346)
4	CONSERVATION	-	(2,393,460)	-	-	-	-	-	-	(2,393,460)	(2,393,460)	(3,885,304)
5	UNBUNDLING	-	-	-	-	-	-	-	-	-	-	-
6	GROSS RECEIPTS TAX	-	-	-	-	-	-	-	-	-	-	-
7	FRANCHISE TAX	-	-	-	-	-	-	-	-	-	-	-
8	OTHER OPERATING REVENUES	(2,277,742)	117,912	-	(517,361)	(30,301)	-	-	-	(2,707,492)	(2,707,492)	(4,395,072)
9												
10	**TOTAL REVENUE ADJUSTMENTS**	(32,295,204)	(2,275,548)	-	(517,361)	(30,301)	-	-	-	(35,118,414)	(35,118,414)	(57,007,721)
11												
12	**OPERATING EXPENSES**											
13	OPERATION	-	-	-	-	-	-	(24,621)	-	(24,621)	(24,621)	(39,967)
14	MAINTENANCE	-		-	-	-	-	-	-	-		-
15	COST OF GAS	32,319,861	-	-	-	-	-	-	-	32,319,861	32,319,861	52,464,830
16	CONSERVATION	-	2,292,190	-	-	-	-	-	-	2,292,190	2,292,190	3,720,912
17	STORAGE & UNBUNDLING	-	-		-	-	-	-	-	-	-	-
18	DEPRECIATION	-	-	-	-	-	108,001	-	108,001	-	108,001	175,318
19	AMORTIZATION	-	-	-	514,774	-	-	-	-	514,774	514,774	835,633
20	TAXES OTHER THAN INCOME	149,489	12,569		2,587	-	-	(20,312)	-	144,333	144,333	234,296
21	INCOME TAX - FEDERAL	(65,529)	(10,911)	(98,711)	-	11,402	(40,641)	16,908	(40,641)	(146,841)	(187,482)	(304,340)
22	INCOME TAX - STATE	-	-	-	-	-	-	-	-	-	-	-
23	DEFERRED INCOME TAX - FEDERAL	-	-	-	-	-	-	-	-	-	-	-
24	DEFERRED INCOME TAX - STATE	-	-	-	-	-	-	-	-	-	-	-
25	INVESTMENT TAX CREDIT	-	-	-	-	-	-	-	-	-	-	-
27	GAIN/LOSS ON DISPOSAL OF PLANT	-	-	-	-	-	-	-	-	-	-	-
26												
27	**TOTAL EXPENSE ADJUSTMENTS**	32,403,821	2,293,848	(98,711)	517,361	11,402	67,360	(28,025)	67,360	35,099,696	35,167,056	57,086,682
28												
29	**NET ADJUSTMENTS**	108,617	18,300	(98,711)	-	(18,899)	67,360	(28,025)	67,360	(18,718)	48,642	78,960

* All adjustments consistent with those made in the Company's last rate proceeding (Excluding item 5 and item 7).

SUPPORTING SCHEDULES: C-2 p.2-3, C-7

RECAP SCHEDULES: C-1

Schedule C-2 JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF PROPOSED ADJUSTMENTS TO NET OPERATING JURISDICTIONAL COMPONENTS, AND THE REVENUE REQUIREMENT EFFECT ON EACH AND THE TOTAL. INDICATE WHICH ADJUSTMENTS WERE MADE IN THE COMPANY'S LAST FULL REVENUE REQUIREMENTS CASE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

Line No.	REASON FOR ADJUSTMENT	ADJUSTMENT CATEGORY	DESCRIPTION	NUMBER	AMOUNT	JURISDICTIONAL FACTOR	JURISDICTIONAL AMOUNT	NONUTILITY AMOUNT	REGULATED AMOUNT	COMPANY VS COMMISSION	**CHANGE IN REV REQ**
1	Eliminate Fuel Revenues	FUEL REV	01 FUEL	12*.4000.4***2	(30,017,462)	100%	(30,017,462)	-	(30,017,462)	COMMISSION	(48,727,346)
2	Eliminate Conservation Revenue and Recoveries	CONS REV	02 CONS	12*.4000.48**5	(2,393,460)	100%	(2,393,460)	-	(2,393,460)	COMMISSION	(3,885,304)
3	Eliminate Conservation Revenue and Recoveries	CONS REV	02 CONS	12*.4957	117,912	100%	117,912	-	117,912	COMMISSION	191,407
4	Eliminate Fuel Overrecovery	OTHER REV	01 FUEL	12*.4000.4951	(2,277,742)	100%	(2,277,742)	-	(2,277,742)	COMMISSION	(3,697,459)
5	Eliminate Area Expansion Program Revenue	OTHER REV	04 AEP	12*.4000.4956	(517,361)	100%	(517,361)	-	(517,361)	COMMISSION	(839,832)
6	Eliminate Fuel Expense	FUEL EXP	01 FUEL	12*.4010.80***	32,319,861	100%	32,319,861	-	32,319,861	COMMISSION	52,464,830
7	Eliminate Conservation Expense and Recoveries	CONS EXP	02 CONS	12*.4010.907	2,292,190	100%	2,292,190	-	2,292,190	COMMISSION	3,720,912
8	Exclude Non-Utility Depreciation Expense	DEP	06 NON-UTILITY	12*.4030.1	107,484	100%	107,484	107,484	-	COMMISSION	174,479
9	Misc. Allocation Adjustment	DEP	06 NON-UTILITY	12*.4030.2	517	100%	517	517	-	COMMISSION	839
10	Eliminate Area Expansion Program Expense	AMORT	04 AEP	12*.4070.5	514,774	100%	514,774	-	514,774	COMMISSION	835,633
11	Eliminate Taxes Other Than Income on Fuel	TOTI	01 FUEL	12*.4080.2 & .3	149,489	100%	149,489	-	149,489	COMMISSION	242,665
12	Eliminate Taxes Other Than Income on Conservation	TOTI	02 CONS	12*.4080.2 & .3	12,569	100%	12,569	-	12,569	COMMISSION	20,403
13	Eliminate Taxes Other Than Income on AEP	TOTI	04 AEP	12*.4080.2 & .3	2,587	100%	2,587	-	2,587	COMMISSION	4,199
14	Eliminate IT on Profit/Loss on Fuel Cost Recoveries	IT	01 FUEL	12*.4090.1 & .2	(922,644)	100%	(922,644)	-	(922,644)	COMMISSION	(1,497,728)
15	Eliminate IT on Profit/Loss on Fuel O/U Recovery	IT	01 FUEL	12*.4090.1 & .2	857,115	100%	857,115	-	857,115	COMMISSION	1,391,355
16	Eliminate IT on Profit/Loss on Conservation	IT	02 CONS	12*.4090.1 & .2	(10,911)	100%	(10,911)	-	(10,911)	COMMISSION	(17,712)
17	Interest and Income Tax Synchronization	IT	03 OTHER	12*.4090.1 & .2	(36,149)	100%	(36,149)	-	(36,149)	COMMISSION	(58,681)
18	Eliminate IT on Estimated 2006 Over Earnings	IT	05 OOPOE	12*.4090.1 & .2	17,460	100%	17,460	-	17,460	COMMISSION	28,343
19	Eliminate IT on Estimated 2005 Over Earnings	IT	05 OOPOE	12*.4090.1 & .2	(6,058)	100%	(6,058)	-	(6,058)	COMMISSION	(9,834)
20	Rate Refund Adjustment - 2006 Over Earnings	OTHER REV	05 OOPOE	12*.4000.496	(46,400)	100%	(46,400)	-	(46,400)	COMMISSION	(75,321)
21	Rate Refund Adjustment - 2005 Over Earnings	OTHER REV	05 OOPOE	12*.4000.4953	16,099	100%	16,099	-	16,099	COMMISSION	26,134
22	Include Sales Expense from Disallowed Conservation	OP EXP	07 OOPCON	12*.4010.9132	23,035	100%	23,035	-	23,035	COMMISSION	37,393
23	Eliminate Conservation 2006 Adjustment	OP EXP	07 OOPCON	12*.4010.92**	(47,656)	100%	(47,656)	-	(47,656)	COMMISSION	(77,360)
24	Eliminate TOTI charged to conservation	TOTI	07 OOPCON	12*.4080.5,6,7	(20,312)	100%	(20,312)	-	(20,312)	COMMISSION	(32,972)
25	IT on Sales and PR Fringe Expense	IT	07 OOPCON	12*.4090.1 & .2	9,265	100%	9,265	-	9,265	COMMISSION	15,040
26	IT on TOTI	IT	07 OOPCON	12*.4090.1 & .2	7,643	100%	7,643	-	7,643	COMMISSION	12,407
27	Eliminate IT on Non-Utility Depreciation Expense	IT	06 NON-UTILITY	12*.4090.1 & .2	(40,641)	100%	(40,641)	(40,641)	-	COMMISSION	(65,973)
28	Income tax adjustment	IT	03 OTHER	12*.4090.1 & .2	(62,562)	100%	(62,562)	-	(62,562)	COMMISSION	(101,557)
29											
30											
31	TOTAL ADJUSTMENTS						48,642	67,360	(18,718)		78,960

SUPPORTING SCHEDULES: C-2 p.2-3, C-7 RECAP SCHEDULES: C-1

SCHEDULE C-3	OPERATING REVENUES	PAGE 1 OF 4
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: PROVIDE A SCHEDULE OF OPERATING REVENUE BY MONTH, AND IN TOTAL BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/2007
COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU		WITNESS: COX

LINE NO.	A/C NO.	DESCRIPTION	(1)	(2) Year End 2007	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				ADJUSTMENTS				TAXES				
		GAS SALES	TOTAL PER BOOKS	FUEL REVENUES	CONSERVATION REVENUES	UNBUNDLING ONGOING REVENUES	UNBUNDLING INITIAL REVENUES	GROSS RECEIPTS TAX REVENUES	FRANCHISE TAX REVENUES	OTHER	TOTAL (2)-(7)	BASE REVENUES
1	4800*	RES	(21,523,827)	(8,972,620)	(1,067,161)	-	-	(633,527)	(655,497)		(11,328,805)	(10,195,022)
2	4810*	CS	(14,545,354)	(8,844,388)	(462,828)	-	-	(436,433)	(418,828)		(10,162,477)	(4,382,877)
3	4811*	CL	(19,641,535)	(13,328,157)	(494,189)	-	-	(517,302)	(451,016)		(14,790,664)	(4,850,871)
4	4812*	INT	(121,553)	(103,304)	-	-	-	(1,025)	-		(104,329)	(17,224)
5	4890*	TRANS CS	(415,784)	-	(38,408)	-	-	(33,368)	-		(71,776)	(344,008)
6	4891*	TRANS CL	(3,902,444)	-	(330,874)	-	-	(325,715)	-		(656,589)	(3,245,855)
7	4892*	TRANS INT	(775,598)	-	-	-	-	(146,569)	-		(146,569)	(629,029)
8	4893*	TRANS LV INT	-	-	-	-	-	-	-		-	-
9	4813*	LAKE WORTH	-	-	-	-	-	-	-		-	-
10	4814*	INTERDEPARTMENTAL	(53,646)	(50,045)	-	-	-	(1,863)	(1,738)		(53,646)	-
11	4898*	POOL	1,423,284	1,429,484	-	-	-	-	-		1,429,484	(6,200)
12	4814*	OUTDOOR LIGHTS	(238,939)	(148,432)	-	-	-	(10,536)	(6,408)		(165,376)	(73,563)
13	4954*	OSS (BASE + CUSTOMER)	-	-	-	-	-	-	-		-	-
14												
15		TOTAL REVENUES	(59,795,396)	(30,017,462)	(2,393,460)	-	-	(2,106,338)	(1,533,487)	-	(36,050,747)	(23,744,649)
16												

LINE NO.	A/C NO.	DESCRIPTION	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				ADJUSTMENTS				TAXES				
		OTHER OPERATING REVENUES	TOTAL PER BOOKS	FUEL REVENUES	CONSERVATION REVENUES	UNBUNDLING ONGOING REVENUES	UNBUNDLING INITIAL REVENUES	GROSS RECEIPTS TAX REVENUES	FRANCHISE TAX REVENUES	OTHER	TOTAL (2)-(7)	TOTAL OTHER REVENUES
17	487	LATE FEES	(779,563)								-	(779,563)
18	4880	MISC SERVICE REV-OTHER CHARGE	(58,394)								-	(58,394)
19	4881	MISC SERVICE REV-CREDIT	(2,044)								-	(2,044)
20	4882	MISC SERVICE REV-CHECK CHARGE	(31,691)								-	(31,691)
21	4884	MISC SVC REV-CHANGE OF ACCOUNT	(37,066)								-	(37,066)
22	4885	MISC SVC REV-RECONNECT CHARGE	(270,292)									(270,292)
23	4886	MISC SVC REV-RECONNECT NON-PAY	(287,899)									(287,899)
24	4887	MISC SVC REV-BILL COLLECT CHG	(76,112)									(76,112)
25	4888	MISC SVC REV-ALLOWANCES & ADJ	13,255									13,255
26	493	RENT FROM GAS PROPERTY	-								-	-
27	4951	OVER REC;FUEL ADJ- PURCHAS GAS	(2,277,742)	(2,277,742)							(2,277,742)	-
28	4952	MISC.GAS REVENUE	(43,079)								-	(43,079)
29	4953	UNBILLED REVENUES	98,445								-	98,445
30	49549	CUSTOMER OSS REVENUE	-	-							-	-
31	4956	OTHER GAS REVENUE - AEP	(517,361)							(517,361)	(517,361)	-
32	49561	OTHER GAS REV - STORM	(163,828)							-	-	(163,828)
33	4957	OVERRECOVERY:GAS CONSERVATION	117,912		117,912						117,912	-
34	4958	OVRRECV UNBUNDLNG ONGOING CSTS	-			-					-	-
35	49551	BASE RVENUE-L WORTH GENERATION	(708,870)								-	(708,870)
36	49581	OVRRECV UNBUNDLNG INITIAL CSTS	-				-				-	-
37	496	RATE REFUND PENDING ACCOUNTS	(30,301)							(30,301)	(30,301)	-
38												
39		TOTAL OTHER OPERATING REVENUES	(5,054,630)	(2,277,742)	117,912	-	-	-	-	(547,662)	(2,707,492)	(2,347,138)
40												
41												
42		TOTAL OPERATING REVENUES	(64,850,026)	(32,295,204)	(2,275,548)	-	-	(2,106,338)	(1,533,487)	(547,662)	(38,758,239)	(26,091,787)

SUPPORTING SCHEDULES: C-3 p.2,3

RECAP SCHEDULES: C-1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE OF OPERATING REVENUE BY MONTH, AND IN TOTAL BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07	(13) TOTAL
		BASE REVENUES													
1	48001	RES	(1,076,678)	(1,118,519)	(1,103,200)	(928,424)	(814,903)	(759,176)	(685,287)	(644,651)	(634,315)	(707,975)	(799,977)	(921,917)	(10,195,022)
2	48101	CS	(506,043)	(491,273)	(512,647)	(421,214)	(353,570)	(313,095)	(270,415)	(238,751)	(235,646)	(280,467)	(341,801)	(417,955)	(4,382,877)
3	48111	CL	(462,550)	(424,872)	(496,667)	(420,440)	(363,286)	(404,855)	(374,955)	(370,804)	(346,347)	(381,082)	(388,430)	(416,583)	(4,850,871)
4	48121	INT	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(3,516)	(3,003)	(3,477)	(3,433)	(3,585)	(17,224)
5	48901	TRANS CS	(34,995)	(31,269)	(38,469)	(31,556)	(27,793)	(26,107)	(24,152)	(23,131)	(17,797)	(25,600)	(30,466)	(32,673)	(344,008)
6	48911	TRANS CL	(295,046)	(271,692)	(303,991)	(284,756)	(276,277)	(269,396)	(276,517)	(263,944)	(239,065)	(267,212)	(244,672)	(253,287)	(3,245,855)
7	48921	TRANS INT	(55,083)	(53,722)	(56,016)	(57,575)	(52,963)	(50,822)	(49,831)	(49,031)	(50,038)	(50,875)	(51,170)	(51,903)	(629,029)
8	48931	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
9	4813	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
10	48401	INDEPARTMENTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
11	48981	POOL	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(600)	(600)	(6,200)
12	48141	OUTDOOR LIGHTS	(7,396)	(7,251)	(7,392)	(7,385)	(2,274)	(7,221)	(7,220)	(7,407)	(7,403)	(7,422)	2,551	(7,743)	(73,563)
13	49541	OSS (BASE + CUSTOMER)	-	-	-	-	-	-	-	-	-	-	-	-	-
14															
15		TOTAL BASE REVENUES	(2,438,321)	(2,399,128)	(2,518,912)	(2,151,880)	(1,891,596)	(1,831,202)	(1,688,907)	(1,601,735)	(1,534,114)	(1,724,610)	(1,857,998)	(2,106,246)	(23,744,649)
16															
17															
18		**FUEL REVENUES**													
19															
20	48002	RES	(1,169,091)	(1,238,365)	(1,211,662)	(926,406)	(734,398)	(643,179)	(492,311)	(399,846)	(333,289)	(409,464)	(623,266)	(791,343)	(8,972,620)
21	48102	CS	(1,133,028)	(1,099,009)	(1,150,937)	(923,602)	(755,317)	(655,381)	(513,234)	(409,992)	(343,148)	(423,799)	(635,412)	(801,529)	(8,844,388)
22	48112	CL	(1,395,809)	(1,262,680)	(1,514,092)	(1,255,214)	(1,058,778)	(1,197,898)	(1,028,600)	(946,870)	(743,061)	(837,676)	(997,515)	(1,089,964)	(13,328,157)
23	48122	INT	-	-	-	-	-	-	-	(22,630)	(16,336)	(19,165)	(22,057)	(23,116)	(103,304)
24	48902	TRANS CS	-	-	-	-	-	-	-	-	-	-	-	-	-
25	48912	TRANS CL	-	-	-	-	-	-	-	-	-	-	-	-	-
26	48922	TRANS INT	-	-	-	-	-	-	-	-	-	-	-	-	-
27	48932	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
28	49552	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
29	48402	INDEPARTMENTAL	(4,184)	(3,421)	(4,499)	(3,909)	(5,159)	(5,073)	(5,497)	(5,728)	(3,189)	(2,403)	(3,945)	(3,038)	(50,045)
30	48982	POOL	163,512	248,003	141,790	91,316	85,755	144,831	112,524	91,859	106,990	84,170	124,033	34,701	1,429,484
31	48142	OUTDOOR LIGHTS	(20,918)	(20,270)	(20,702)	(20,759)	5,081	(19,320)	(18,115)	(17,563)	(15,039)	(15,058)	30,904	(16,673)	(148,432)
32	49542	OSS (BASE + CUSTOMER)	-	-	-	-	-	-	-	-	-	-	-	-	-
33															
34		TOTAL FUEL REVENUES	(3,559,518)	(3,375,742)	(3,760,102)	(3,038,574)	(2,462,816)	(2,376,020)	(1,945,233)	(1,710,770)	(1,347,072)	(1,623,395)	(2,127,258)	(2,690,962)	(30,017,462)
35															

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-3 p.1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE OF OPERATING REVENUE BY MONTH, AND IN TOTAL BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07	(13) TOTAL
36															
37		**CONSERVATION REVENUES**													
38															
39	48005	RES	(131,171)	(138,865)	(135,867)	(103,900)	(82,364)	(72,124)	(58,926)	(51,515)	(50,002)	(61,329)	(79,725)	(101,373)	(1,067,161)
40	48105	CS	(55,769)	(54,099)	(56,654)	(45,465)	(37,061)	(32,261)	(26,973)	(23,159)	(22,709)	(27,874)	(35,706)	(45,098)	(462,828)
41	48115	CL	(48,024)	(43,626)	(52,078)	(43,183)	(36,429)	(41,272)	(37,802)	(37,211)	(34,089)	(38,450)	(39,199)	(42,826)	(494,189)
42	48125	INT	-	-	-	-	-	-	-	-	-	-	-	-	-
43	48905	TRANS CS	(3,994)	(3,538)	(4,430)	(3,555)	(3,079)	(2,874)	(2,631)	(2,510)	(1,879)	(2,801)	(3,422)	(3,695)	(38,408)
44	48915	TRANS CL	(30,258)	(28,063)	(31,878)	(29,494)	(28,367)	(27,336)	(28,138)	(26,565)	(23,560)	(26,684)	(24,793)	(25,738)	(330,874)
45	48925	TRANS INT	-	-	-	-	-	-	-	-	-	-	-	-	-
46	48935	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
47	48135	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
48	48405	INDEPARTMENTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
49	48985	POOL	-	-	-	-	-	-	-	-	-	-	-	-	-
50	48145	OUTDOOR LIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-
51	49545	OSS	-	-	-	-	-	-	-	-	-	-	-	-	-
52															
53		TOTAL CONSERVATION REVENUES	(269,216)	(268,191)	(280,907)	(225,597)	(187,300)	(175,867)	(154,470)	(140,960)	(132,239)	(157,138)	(182,845)	(218,730)	(2,393,460)
54															
55															
56		**UNBUNDLING ONGOING REVENUES**													
57															
58	48007	RES	-	-	-	-	-	-	-	-	-	-	-	-	-
59	48107	CS	-	-	-	-	-	-	-	-	-	-	-	-	-
60	48117	CL	-	-	-	-	-	-	-	-	-	-	-	-	-
61	48127	INT	-	-	-	-	-	-	-	-	-	-	-	-	-
62	48907	TRANS CS	-	-	-	-	-	-	-	-	-	-	-	-	-
63	48917	TRANS CL	-	-	-	-	-	-	-	-	-	-	-	-	-
64	48927	TRANS INT	-	-	-	-	-	-	-	-	-	-	-	-	-
65	48937	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
66	48137	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
67	48407	INDEPARTMENTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
68	48987	POOL	-	-	-	-	-	-	-	-	-	-	-	-	-
69	48147	OUTDOOR LIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-
70	49547	OSS	-	-	-	-	-	-	-	-	-	-	-	-	-
71															
72		TOTAL CONSERVATION REVENUES	0	0	0	0	0	0	0	0	0	0	0	0	0
73															
74															
75		**UNBUNDLING INITIAL REVENUES**													
76															
77	480071	RES	-	-	-	-	-	-	-	-	-	-	-	-	-
78	481071	CS	-	-	-	-	-	-	-	-	-	-	-	-	-
79	481171	CL	-	-	-	-	-	-	-	-	-	-	-	-	-
80	481271	INT	-	-	-	-	-	-	-	-	-	-	-	-	-
81	489071	TRANS CS	-	-	-	-	-	-	-	-	-	-	-	-	-
82	489171	TRANS CL	-	-	-	-	-	-	-	-	-	-	-	-	-
83	489271	TRANS INT	-	-	-	-	-	-	-	-	-	-	-	-	-
84	489371	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
85	481371	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
86	48407	INDEPARTMENTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
87	48987	POOL	-	-	-	-	-	-	-	-	-	-	-	-	-
88	481471	OUTDOOR LIGHTS	-	-	-	-	-	-	-	-	-	-	-	-	-
89	495471	OSS	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91		TOTAL CONSERVATION REVENUES	0	0	0	0	0	0	0	0	0	0	0	0	0
92															

SUPPORTING SCHEDULES: C-3, p. 2,3

RECAP SCHEDULES: C-1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE OF OPERATING REVENUE BY MONTH, AND IN TOTAL BY PRIMARY ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07	(13) TOTAL
93															
94		**GROSS RECEIPTS TAX REVENUES**													
95															
96	48003	RES	(76,372)	(80,935)	(79,305)	(60,064)	(47,865)	(42,175)	(36,073)	(31,622)	(30,475)	(37,637)	(48,889)	(62,115)	(633,527)
97	48103	CS	(51,221)	(49,318)	(50,756)	(41,518)	(34,976)	(31,294)	(26,576)	(23,179)	(23,051)	(27,809)	(33,753)	(42,982)	(436,433)
98	48113	CL	(50,076)	(45,029)	(54,720)	(44,283)	(37,575)	(42,448)	(40,051)	(40,198)	(36,553)	(41,477)	(40,740)	(44,152)	(517,302)
99	48123	INT	-	-	-	204	-	-	-	-	-	(30)	(36)	(1,163)	(1,025)
100	48903	TRANS CS	(3,384)	(3,007)	(3,779)	(3,172)	(2,622)	(2,458)	(2,325)	(2,218)	(1,664)	(2,449)	(3,033)	(3,257)	(33,368)
101	48913	TRANS CL	(34,519)	(31,015)	6,096	(31,462)	(29,983)	(28,923)	(30,227)	(28,717)	(25,870)	(29,896)	(29,899)	(31,300)	(325,715)
102	48923	TRANS INT	(14,257)	(13,137)	(5,702)	(14,054)	(12,671)	(12,496)	(12,087)	(12,044)	(12,395)	(12,393)	(12,542)	(12,791)	(146,569)
103	48933	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
104	49553	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
105	48403	INDEPARTMENTAL	(129)	(106)	(139)	(120)	(159)	(187)	(215)	(241)	(156)	(118)	(166)	(127)	(1,863)
106	48983	POOL	-	-	-	-	-	-	-	-	-	-	-	-	-
107	48143	OUTDOOR LIGHTS	(1,142)	(1,142)	(1,151)	(1,149)	415	(1,144)	(1,160)	(1,184)	(1,183)	(1,185)	733	(1,244)	(10,536)
108	49543	OSS	-	-	-	-	-	-	-	-	-	-	-	-	-
109															
110		TOTAL GROSS RECEIPTS TAX REVENUES	(231,100)	(223,689)	(189,456)	(195,618)	(165,436)	(161,125)	(148,714)	(139,403)	(131,347)	(152,994)	(168,325)	(199,131)	(2,106,338)
111															
112															
113		**FRANCHISE TAX REVENUES**													
114															
115	48004	RES	(81,837)	(83,065)	(82,357)	(64,898)	(51,536)	(45,424)	(37,854)	(32,821)	(30,245)	(36,371)	(47,939)	(61,150)	(655,497)
116	48104	CS	(52,342)	(49,293)	(51,369)	(43,880)	(36,025)	(30,294)	(24,502)	(19,899)	(18,139)	(22,180)	(31,801)	(39,104)	(418,828)
117	48114	CL	(46,725)	(42,097)	(53,560)	(40,889)	(31,440)	(38,179)	(34,147)	(32,970)	(26,402)	(31,450)	(34,876)	(38,281)	(451,016)
118	48124	INT	-	-	-	-	-	-	-	-	-	-	-	-	-
119	48904	TRANS CS	-	-	-	-	-	-	-	-	-	-	-	-	-
120	48914	TRANS CL	-	-	-	-	-	-	-	-	-	-	-	-	-
121	48924	TRANS INT	-	-	-	-	-	-	-	-	-	-	-	-	-
122	48934	TRANS LV INT	-	-	-	-	-	-	-	-	-	-	-	-	-
123	49554	LAKE WORTH	-	-	-	-	-	-	-	-	-	-	-	-	-
124	48404	INDEPARTMENTAL	(133)	(107)	(143)	(123)	(161)	(156)	(211)	(220)	(34)	(182)	(151)	(117)	(1,738)
125	48984	POOL	-	-	-	-	-	-	-	-	-	-	-	-	-
126	48144	OUTDOOR LIGHTS	(810)	(810)	(810)	(846)	(252)	(789)	(777)	(738)	(659)	(693)	1,538	(762)	(6,408)
127	49544	OSS	-	-	-	-	-	-	-	-	-	-	-	-	-
128															
129		TOTAL GR & FRANCHISE TAX REVENUES	(181,847)	(175,372)	(188,239)	(150,636)	(119,414)	(114,842)	(97,491)	(86,648)	(75,479)	(90,876)	(113,229)	(139,414)	(1,533,487)
130															
131															
132		TOTAL BASE REVENUES	(2,438,321)	(2,399,128)	(2,518,912)	(2,151,880)	(1,891,596)	(1,831,202)	(1,688,907)	(1,601,735)	(1,534,114)	(1,724,610)	(1,857,998)	(2,106,246)	(23,744,649)
133		TOTAL BASE & FUEL REVENUES	(5,997,839)	(5,774,870)	(6,279,014)	(5,190,454)	(4,354,412)	(4,207,222)	(3,634,140)	(3,312,505)	(2,881,186)	(3,348,005)	(3,985,256)	(4,797,208)	(53,762,111)
134		TOTAL SALES OF GAS EXCLUDING TAXES	(6,267,055)	(6,043,061)	(6,559,921)	(5,416,051)	(4,541,712)	(4,383,089)	(3,788,610)	(3,453,465)	(3,013,425)	(3,505,143)	(4,168,101)	(5,015,938)	(56,155,571)
135															
136		TOTAL SALES OF GAS INCLUDING TAXES	(6,680,002)	(6,442,122)	(6,937,616)	(5,762,305)	(4,826,562)	(4,659,056)	(4,034,815)	(3,679,516)	(3,220,251)	(3,749,013)	(4,449,655)	(5,354,483)	(59,795,396)

SCHEDULE C-4

UNBILLED REVENUES

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:PROVIDE (1) THE DETAILED CALCULATION OF THE 13-MONTH AVERAGE BALANCE OF UNBILLED REVENUES INCLUDED IN THE HISTORIC BASE YEAR RATE BASE AND (2) THE DETAILED CALCULATION OF UNBILLED REVENUES INCLUDED IN THE HISTORIC BASE YEAR NET OPERATING INCOME.THE CALCULATIONS SHOULD BE SHOWN ON A MONTHLY BASIS.ALL SUPPORTING SCHEDULES SHOULD BE INSERTED IMMEDIATELY FOLLOWING THIS SCHEDULE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	ACCOUNT 4953 DESCRIPTION	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	13 Mo Avg
	CONSOLIDATED GAS DIVISION														
1	Purchases excl. OSS	594,140	628,415	610,905	606,388	477,201	499,639	411,206	396,985	392,037	388,286	436,695	524,084	559,465	501,957
2	Purchase adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Less: Company Use	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Less: Unaccounted for	(16,136)	(15,060)	(14,587)	(14,875)	(12,332)	(12,231)	(4,112)	(9,409)	(9,317)	(10,472)	(10,545)	(5,241)	(13,739)	(11,389)
5															
6	Net Available For Sale	610,276	643,475	625,492	621,263	489,533	511,870	415,318	406,394	401,354	398,758	447,240	529,325	573,204	513,346
7	Less: Sales excl. OSS	567,613	636,339	614,078	666,320	560,148	477,260	467,390	429,400	404,406	377,676	434,618	467,963	541,520	511,133
8															
9	Unbilled Units	42,663	7,136	11,414	(45,057)	(70,615)	34,610	(52,072)	(23,006)	(3,052)	21,082	12,622	61,362	31,684	2,213
10															
11	Base Revenue Factor	3.043	3.080	3.155	3.063	2.982	2.959	2.891	2.824	2.775	2.762	2.833	2.947	3.014	2.95
12															
13	Cumulative Unbilled Units	314,868	322,004	333,418	288,361	217,746	252,356	200,284	177,278	174,226	195,308	207,930	269,292	300,976	250,311
14															
15	Cumulative Unbilled Revenue	958,100	991,677	1,051,784	883,317	649,302	746,630	579,021	500,701	483,490	539,522	589,017	793,643	907,199	744,108
16	Plus: 1/2 of Customer Charge (est.)	235,430	241,651	239,995	241,856	240,545	241,201	240,250	240,289	239,439	239,460	246,964	241,457	242,517	240,850
17	Net Cumulative Unbilled Revenue	1,193,530	1,233,328	1,291,779	1,125,173	889,847	987,831	819,271	740,990	722,929	778,982	835,981	1,035,100	1,149,716	984,958
18	Adjustments to Unbilled	(1)	-	(165,576)	(155,981)	1	(58,602)	(56,894)	(55,552)	(50,711)	(50,358)	(52,985)	(55,277)	(54,631)	(58,197)
19	Net Cumulative Unbilled Revenue - Adjusted	1,193,529	1,233,328	1,126,203	969,192	889,848	929,230	762,377	685,438	672,217	728,624	782,996	979,823	1,095,085	926,761
20															
21	Total Monthly Unbilled Revenue	154,165	39,798	58,451	(166,606)	(235,325)	97,984	(168,561)	(78,281)	(18,061)	56,053	56,999	199,119	114,616	8,489
22	Adjustments to Unbilled	-	1	(165,577)	9,596	155,982	(58,603)	1,708	1,342	4,841	353	(2,626)	(2,292)	646	(4,202)
23	Total Monthly Unbilled Revenue - Adjusted	154,165	39,799	(107,126)	(157,011)	(79,344)	39,381	(166,853)	(76,939)	(13,221)	56,406	54,373	196,827	115,262	4,286
24															

Supporting Schedules: E1, p1

Recap Schedules: C-3, G-2(C-4), E-1

SCHEDULE C-4 **UNBILLED REVENUES**

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:PROVIDE (1) THE DETAILED CALCULATION OF THE 13-MONTH AVERAGE BALANCE OF UNBILLED REVENUES INCLUDED IN THE HISTORIC BASE YEAR RATE BASE AND (2) THE DETAILED CALCULATION OF UNBILLED REVENUES INCLUDED IN THE HISTORIC BASE YEAR NET OPERATING INCOME.THE CALCULATIONS SHOULD BE SHOWN ON A MONTHLY BASIS.ALL SUPPORTING SCHEDULES SHOULD BE INSERTED IMMEDIATELY FOLLOWING THIS SCHEDULE.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	ACCOUNT 4953 DESCRIPTION	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	13 Mo Avg
25	**WEST PALM BEACH - 121**														
26															
27	Purchases excl. OSS	425,330	438,757	423,884	440,574	378,010	361,689	287,002	271,974	269,831	270,649	308,904	378,401	407,244	358,635
28	Purchase adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-
29	Less: Company Use	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Less: Unaccounted for	(12,760)	(13,163)	(12,717)	(13,217)	(11,340)	(10,851)	(2,870)	(8,159)	(8,095)	(8,119)	(9,267)	(3,784)	(12,217)	(9,735)
31															
32	Net Available For Sale	438,090	451,920	436,601	453,791	389,350	372,540	289,872	280,133	277,926	278,768	318,171	382,185	419,461	368,370
33	Less: Sales excl. OSS	403,391	472,396	432,080	475,213	409,886	336,538	328,781	297,147	276,725	258,316	312,685	331,167	389,717	363,388
34															
35	Unbilled Units	34,699	(20,476)	4,521	(21,422)	(20,536)	36,002	(38,909)	(17,014)	1,201	20,452	5,486	51,018	29,744	4,982
36															
37	Base Revenue Factor	2.993	3.058	3.049	3.028	3.006	2.982	2.895	2.826	2.772	2.753	2.836	2.959	3.018	2.94
38															
39	Cumulative Unbilled Units	215,148	194,672	199,193	177,771	157,235	193,237	154,328	137,314	138,515	158,967	164,453	215,471	245,215	180,886
40															
41	Cumulative Unbilled Revenue	644,018	595,391	607,298	538,319	472,669	576,169	446,753	388,108	384,007	437,655	466,399	637,512	739,961	533,404
42	Plus: 1/2 of Customer Charge (est.)	152,367	157,920	156,799	157,540	157,736	158,052	157,615	157,843	157,742	157,606	164,104	157,416	157,664	157,723
43	Net Cumulative Unbilled Revenue	796,385	753,311	764,097	695,859	630,405	734,221	604,368	545,951	541,749	595,261	630,503	794,928	897,625	691,128
44	Adjustments to Unbilled	(1)	-	(1)			(58,602)	(56,894)	(55,551)	(50,711)	(50,359)	(52,985)	(55,277)	(54,913)	(39,572)
45	Net Cumulative Unbilled Revenue - Adjusted	796,384	753,311	764,096	695,859	630,405	675,619	547,474	490,401	491,037	544,902	577,517	739,651	842,711	657,644
46															
47															
48	Total Monthly Unbilled Revenue	111,537	(43,074)	10,786	(68,238)	(65,454)	103,816	(129,853)	(58,417)	(4,203)	53,513	35,241	164,425	102,697	16,367
49	Adjustments to Unbilled	-	1	(1)	1	-	(58,602)	1,708	1,343	4,840	352	(2,626)	(2,292)	364	(4,224)
50	Total Monthly Unbilled Revenue - Adjusted	111,537	(43,073)	10,785	(68,237)	(65,454)	45,214	(128,145)	(57,074)	637	53,865	32,615	162,133	103,061	12,143
51															
52															
53	**CENTRAL FLORIDA - 123**														
54															
55	Purchases excl. OSS	168,810	189,658	187,021	165,814	99,191	137,950	124,204	125,011	122,206	117,637	127,791	145,683	152,221	143,323
56	Purchase adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-
57	Less: Company Use	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Less: Unaccounted for	-3376	(1,897)	(1,870)	(1,658)	(992)	(1,380)	(1,242)	(1,250)	(1,222)	(2,353)	(1,278)	(1,457)	(1,522)	(1,654)
59															
60	Net Available For Sale	172,186	191,555	188,891	167,472	100,183	139,330	125,446	126,261	123,428	119,990	129,069	147,140	153,743	144,976
61	Less: Sales excl. OSS	164,222	163,943	181,998	191,107	150,262	140,722	138,609	132,253	127,681	119,360	121,933	136,796	151,803	147,745
62															
63	Unbilled Units	7,964	27,612	6,893	(23,635)	(50,079)	(1,392)	(13,163)	(5,992)	(4,253)	630	7,136	10,344	1,940	(2,769)
64															
65	Base Revenue Factor	3.14964	3.112	3.312	3.120	2.919	2.883	2.878	2.817	2.786	2.803	2.820	2.901	2.999	3
66															
67	Cumulative Unbilled Units	99720	127,332	134,225	110,590	60,511	59,119	45,956	39,964	35,711	36,341	43,477	53,821	55,761	69,425
68															
69	Cumulative Unbilled Revenue	314,082	396,286	444,486	344,998	176,633	170,461	132,267	112,592	99,483	101,866	122,618	156,131	167,238	210,703
70	Plus: 1/2 of Customer Charge (est.)	83063	83,731	83,196	84,316	82,809	83,149	82,635	82,446	81,697	81,854	82,860	84,041	84,853	83,127
71	Net Cumulative Unbilled Revenue	397,145	480,017	527,682	429,314	259,442	253,610	214,902	195,038	181,180	183,720	205,478	240,172	252,091	293,830
72	Adjustments to Unbilled	-	-	(165,575)	(155,981)	1	-	-	(1)	-	1	-	-	282	(24,713)
73	Net Cumulative Unbilled Revenue - Adjusted	397,145	480,017	362,107	273,333	259,443	253,610	214,902	195,037	181,180	183,721	205,478	240,172	252,373	269,117
74															
75															
76	Total Monthly Unbilled Revenue	42,628	82,872	47,665	(98,368)	(169,871)	(5,832)	(38,708)	(19,864)	(13,858)	2,540	21,758	34,694	11,919	(7,879)
77	Adjustments to Unbilled			(165,576)	9,595	155,982	(1)	-	(1)	1	1	-	-	282	26
78	Total Monthly Unbilled Revenue - Adjusted	42,628	82,872	(117,911)	(88,774)	(13,890)	(5,833)	(38,708)	(19,865)	(13,857)	2,541	21,758	34,694	12,201	(7,857)

Supporting Schedules: E1, p1

Recap Schedules: C-3, G-2(C-4), E-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07
		GAS SUPPLY EXPENSE - OPERATION												
1	8011	COMMODITY OTHER-SYSTEM SUPPLY	2,722,364	3,475,539	3,267,264	2,639,345	2,026,799	1,713,261	1,937,268	1,580,982	1,376,998	1,648,392	2,721,865	2,890,906
2	8041	DEMAND/RESERV CHG-PIPE PURCH	-	-	-	-	-	-	-	-	-	-	-	-
3	8042	COMMODITY PIPELINE-SYSTEM SUPP	16,453	17,231	18,649	(29,317)	13,044	403,953	11,732	11,429	11,556	6,304	33,864	10,169
4	8045	DEMAND SYSTEM SUPPLY	506,127	451,179	449,027	424,348	148,900	143,955	150,815	151,097	145,912	170,758	508,193	535,898
5	80472	COMMODITY PIPELINE - TRANS	-	-	-	-	-	-	-	-	-	-	-	-
6	80473	DEMAND TRASPORTATION	-	-	-	-	-	-	-	-	-	-	-	-
7	80491	COMMODITY OTHER OFF SYSTEM SAL	-	-	-	-	-	-	-	-	-	-	-	-
8	80492	COMMODITY PIPELINE - OFFSYSTEM	-	-	-	-	-	-	-	-	-	-	-	-
9	80493	DEMAND - OFF SYSTEM SALES	-	-	-	-	-	-	-	-	-	-	-	-
10	8051	UNDER RECOVERY PURCHASED GAS	-	-	-	-	-	-	-	-	-	-	-	-
11	8073	PURCHASED GAS CALCULATION EXP	-	-	-	-	-	-	-	-	-	-	-	-
12	8074	OTHER PURCHASED GAS EXPENSE	-	-	-	-	-	-	-	-	-	-	-	-
13	8075	PURCHASED GAS EXPENSE	591	482	636	550	725	743	869	926	145	689	650	596
14	810	GAS USED FOR COMPRESSOR STATN	-	-	-	-	-	-	-	-	-	-	-	-
15	813	OTHER GAS SUPPLY EXPENSE	13,732	11,850	15,656	11,816	13,555	12,354	10,169	15,394	13,235	15,340	17,930	12,566
16		**COST OF GAS EXCL 4010.813 (OTHER)**	3,245,535	3,944,431	3,735,576	3,034,926	2,189,468	2,261,912	2,100,684	1,744,434	1,534,611	1,826,143	3,264,572	3,437,569
17		**OTHER GAS SUPPLY EXPENSE 4010.813**	13,732	11,850	15,656	11,816	13,555	12,354	10,169	15,394	13,235	15,340	17,930	12,566
		STORAGE & PROCESSING - UNDERGROUND STORAGE												
18	814	ONGOING UNBUNDLING COSTS	498	478	963	290	1,984	(9)	218	263	377	435	96	477
19	8141	INITIAL UNBUNDLING COSTS	-	-	-	-	-	-	-	-	-	-	-	-
20	815	UNDRECV UNBUNDLNG ONGOING CSTS	-	-	-	-	-	-	-	-	-	-	-	-
21	8151	UNDRECV UNBUNDLNG INITIAL CSTS	-	-	-	-	-	-	-	-	-	-	-	-
22		**TOTAL STORAGE & PROCESSING**	498	478	963	290	1,984	(9)	218	263	377	435	96	477
		OPERATION EXPENSES												
		DISTRIBUTION EXPENSES												
23	870	OPER SUPERVISION & ENGINEERING	31,890	30,835	33,993	32,666	36,189	25,943	26,968	30,003	25,726	26,354	29,053	28,432
24	8711	DISTRIBUTION LOAD DISPATCHING	1,012	1,018	397	1,687	1,040	1,068	679	1,315	991	1,069	1,125	1,214
25	874	MAINS & SERVICES EXPENSE	138,328	118,088	128,981	127,507	133,088	136,152	118,178	122,037	127,888	111,839	140,586	131,964
26	8751	MEAS/REGULATING STN EXP-GENERL	-	-	-	-	-	-	-	-	-	-	-	-
27	8754	M&R STN-SCADA MNT-REPLACE PTS	-	-	-	-	-	-	-	-	-	-	-	-
28	8761	MEAS/REGULATING STN EXP-INDUSL	1,114	943	960	1,222	1,120	1,069	677	971	1,027	1,158	1,135	1,983
29	8771	MEAS/REG STN EXP-CITY GATE CK	2,158	1,489	2,288	1,845	1,519	1,309	935	1,220	1,292	1,348	1,674	1,543
30	878	METER & HOUSE REGULATOR EXP	128,522	119,202	132,235	126,731	124,084	114,205	127,156	120,087	113,156	133,862	131,762	151,392
31	8791	CUSTOMER SERVICE EXP-NO CHG WK	16,651	18,977	17,537	19,492	17,307	18,644	17,302	14,849	18,670	18,441	22,001	26,710
32	8792	CUSTOMER SERVICE EXP-WARRANTY	4,169	4,359	4,398	4,365	4,832	3,763	3,539	4,046	3,624	3,591	4,573	4,545
33	8793	CUST SERV EXP-CHG NO PARTS NEC	(17,699)	(13,357)	(12,115)	(10,186)	(5,594)	(4,766)	(5,904)	(7,527)	(3,296)	(4,961)	(11,600)	(6,354)
34	8801	OTHER EXPENSES MAPS & RECORDS	8,903	7,510	8,547	8,032	6,239	5,796	7,615	8,928	9,236	8,243	9,110	16,398
35	8802	OTHER EXPENSES MISCELLANEOUS	61,434	47,659	53,976	54,794	50,130	45,686	46,868	50,900	53,577	55,104	50,737	96,482
36	881	RENTS	2,206	2,206	17,873	3,529	9,347	12,098	1,448	1,448	800	1,491	700	1,491

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(13) Unadjusted Total	(14) Unadjusted Payroll	(15) Unadjusted Non-Payroll	(16) Payroll Adjustments	(17) Non-Payroll Adjustments	(18) Adjusted Payroll	(19) Adjusted Non-Payroll	(20) Adjusted Total
		GAS SUPPLY EXPENSE - OPERATION								
1	8011	COMMODITY OTHER-SYSTEM SUPPLY	28,000,983	-	28,000,983	-	(28,000,983)	-	-	-
2	8041	DEMAND/RESERV CHG-PIPE PURCH	-	-	-	-	-	-	-	-
3	8042	COMMODITY PIPELINE-SYSTEM SUPP	525,067	-	525,067	-	(525,067)	-	-	-
4	8045	DEMAND SYSTEM SUPPLY	3,786,209	-	3,786,209	-	(3,786,209)	-	-	-
5	80472	COMMODITY PIPELINE - TRANS	-	-	-	-	-	-	-	-
6	80473	DEMAND TRASPORTATION	-	-	-	-	-	-	-	-
7	80491	COMMODITY OTHER OFF SYSTEM SAL	-	-	-	-	-	-	-	-
8	80492	COMMODITY PIPELINE - OFFSYSTEM	-	-	-	-	-	-	-	-
9	80493	DEMAND - OFF SYSTEM SALES	-	-	-	-	-	-	-	-
10	8051	UNDER RECOVERY PURCHASED GAS	-	-	-	-	-	-	-	-
11	8073	PURCHASED GAS CALCULATION EXP	-	-	-	-	-	-	-	-
12	8074	OTHER PURCHASED GAS EXPENSE	-	-	-	-	-	-	-	-
13	8075	PURCHASED GAS EXPENSE	7,602	-	7,602	-	(7,602)	-	-	-
14	810	GAS USED FOR COMPRESSOR STATN	-	-	-	-	-	-	-	-
15	813	OTHER GAS SUPPLY EXPENSE	163,597	143,301	20,296	-	-	143,301	20,296	163,597
16		COST OF GAS EXCL 4010.813 (OTHER)	32,319,861	-	32,319,861	-	(32,319,861)	-	-	-
17		OTHER GAS SUPPLY EXPENSE 4010.813	163,597	143,301	20,296	-	-	143,301	20,296	163,597
		STORAGE & PROCESSING - UNDERGROUND STORAGE								
18	814	ONGOING UNBUNDLING COSTS	6,070	3,416	2,654	-	-	3,416	2,654	6,070
19	8141	INITIAL UNBUNDLING COSTS	-	-	-	-	-	-	-	-
20	815	UNDRECV UNBUNDLNG ONGOING CSTS	-	-	-	-	-	-	-	-
21	8151	UNDRECV UNBUNDLNG INITIAL CSTS	-	-	-	-	-	-	-	-
22		TOTAL STORAGE & PROCESSING	6,070	3,416	2,654	-	-	3,416	2,654	6,070
		OPERATION EXPENSES								
		DISTRIBUTION EXPENSES								
23	870	OPER SUPERVISION & ENGINEERING	358,052	288,344	69,708	-	-	288,344	69,708	358,052
24	8711	DISTRIBUTION LOAD DISPATCHING	12,615	434	12,181	-	-	434	12,181	12,615
25	874	MAINS & SERVICES EXPENSE	1,534,636	705,980	828,656	-	-	705,980	828,656	1,534,636
26	8751	MEAS/REGULATING STN EXP-GENERL	-	-	-	-	-	-	-	-
27	8754	M&R STN-SCADA MNT-REPLACE PTS	-	-	-	-	-	-	-	-
28	8761	MEAS/REGULATING STN EXP-INDUSL	13,379	686	12,693	-	-	686	12,693	13,379
29	8771	MEAS/REG STN EXP-CITY GATE CK	18,620	6,695	11,925	-	-	6,695	11,925	18,620
30	878	METER & HOUSE REGULATOR EXP	1,522,394	1,167,852	354,542	-	-	1,167,852	354,542	1,522,394
31	8791	CUSTOMER SERVICE EXP-NO CHG WK	226,581	170,909	55,672	-	-	170,909	55,672	226,581
32	8792	CUSTOMER SERVICE EXP-WARRANTY	49,804	34,412	15,392	-	-	34,412	15,392	49,804
33	8793	CUST SERV EXP-CHG NO PARTS NEC	(103,359)	72,696	(176,055)	-	-	72,696	(176,055)	(103,359)
34	8801	OTHER EXPENSES MAPS & RECORDS	104,557	81,580	22,977	-	-	81,580	22,977	104,557
35	8802	OTHER EXPENSES MISCELLANEOUS	667,347	291,948	375,399	-	-	291,948	375,399	667,347
36	881	RENTS	54,637	-	54,637	-	-	-	54,637	54,637

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07
		CUSTOMER ACCOUNTS EXPENSES												
37	901	SUPERVISION	12,096	10,520	12,056	11,041	10,461	10,666	11,633	13,099	12,190	11,658	11,644	11,584
38	9011	SUPERVISION- A & G	7,100	6,483	7,431	7,682	7,034	5,643	4,925	3,681	4,240	4,263	4,299	3,414
39	902	METER READING EXPENSES	59,292	52,519	71,251	57,715	57,020	57,179	67,202	55,250	63,183	59,530	59,070	52,142
40	903	CUSTOMER RECORDS & COLLECTION	87,295	78,507	79,401	83,100	86,611	60,258	68,212	74,494	74,267	63,608	73,014	63,680
41	9031	CUST RECORDS/CLLCTN	28,048	38,194	33,444	39,210	27,082	58,274	37,609	37,255	44,164	39,825	48,612	45,209
42	904	UNCOLLECTIBLE ACCOUNTS	26,633	25,805	27,479	22,584	18,689	28,339	12,264	17,252	12,304	14,248	17,182	20,442
43	905	MISC CUSTOMER ACCOUNTS EXP	6,688	8,590	8,100	9,278	7,448	6,597	6,401	7,353	6,697	6,169	7,604	10,387
44	9051	MISC CUST ACCNT EXP	2,490	2,087	2,628	2,456	2,580	2,470	2,203	2,042	2,640	2,587	3,232	2,876
		CUSTOMER SERVICE & INFO												
45	9061	UNDERRECOVERY:CONSERVATION	-	-	-	-	-	-	-	-	-	-	-	-
46	907	SUPERVISION	6,117	5,378	7,450	11,198	9,374	32,173	7,284	13,659	12,394	12,824	12,181	12,178
47	908	CUSTOMER ASSISTANCE EXPENSE	68,853	91,952	117,735	137,653	77,801	186,838	93,450	88,381	78,783	101,155	111,272	125,820
48	909	INFO. & INSTRUCTIONAL ADVERTIS	14,889	20,596	66,411	144,719	68,662	95,777	30,264	94,577	101,856	139,002	51,180	12,066
49	910	MISC CUSTOMER SERVICE & INFO.	1,852	1,192	2,964	1,700	(781)	10,294	6,120	1,881	1,382	1,245	1,401	1,038
		SALES EXPENSES												
50	911	SUPERVISION	12,383	11,564	11,044	12,089	10,764	4,189	8,696	9,196	9,629	12,210	8,643	10,037
51	9121	SELLING EXPENSES	98,514	78,828	82,715	60,620	86,838	70,044	77,211	66,164	65,483	60,829	76,067	68,586
52	9122	DEMONSTRATING EXPENSES	1,164	1,321	2,161	2,246	4,007	11,068	2,950	2,410	1,576	2,904	4,023	2,269
53	9131	PROMOTIONAL ADVERTISING	-	8,666	4,676	5,060	-	9,700	-	-	13,000	4,334	4,333	4,333
54	9132	CONSERVATION ADVERTISING	-	65	-	-	-	23,035	-	-	-	-	-	-
55	9133	SAFETY ADVERTISING	-	105	-	3,966	1,584	3,013	5,751	14,124	1,061	3,862	3,896	3,696
56	9134	OTHER INFOR INSTRU CONS/ADVER	366	152	376	305	250	253	228	320	331	152	230	412
57	9135	COMMUNITY AFFAIRS ADVERTISING	-	-	-	-	-	-	-	-	-	-	-	-
58	9136	OTHER ADVERTISING	1,118	4,219	3,816	1,215	4,244	2,442	2,339	2,559	4,892	1,672	2,879	1,568
59	9161	MISC SALES EXP-PIP & CONV ALLW	37,699	36,859	36,792	36,535	36,253	36,446	36,846	35,485	35,322	36,208	35,600	35,594
60	9162	MISC SALES EXP-PROMO & OTHER	6,476	6,093	14,421	7,266	5,916	5,190	8,900	12,649	10,137	9,935	9,054	10,692
		ADMINISTRATIVE & GENERAL EXPENSES												
61	920	ADMINISTRATIVE & GEN SALARIES	115,374	102,085	126,853	78,451	109,137	108,089	111,550	115,242	100,736	114,451	106,762	120,298
62	9211	OFFICE SUPPLIES	1,588	2,486	1,227	1,635	1,838	2,095	221	2,945	1,245	426	2,439	2,714
63	9212	OFFICE POSTAGE & MAIL SUPPLIES	1,094	1,407	77	1,389	444	338	1,417	1,011	1,487	56	1,451	340
64	9213	OFF COMPUTER SUPPLIES & EXP	525	5,924	1,218	136	1,583	139	1,112	1,048	339	433	1,681	577
65	9214	OFFICE UTILITY EXPENSE	4,894	4,566	2,678	21,044	8,142	8,339	9,473	9,715	7,144	8,967	10,108	10,316
66	9215	MISC OFFICE EXPENSE	14,539	16,527	15,338	12,307	19,115	8,259	20,214	14,506	17,520	7,570	12,339	15,291
67	9216	CO TRAINING EXPENSE-TRACKED	-	-	-	619	3,251	-	-	-	-	-	-	-
68	922	ADMIN EXP TRANSFERRED-CREDIT	-	-	-	-	-	-	-	-	-	-	-	-
69	9231	OUTSIDE SERVICE - OTHER	1,369	-	-	-	-	-	1,650	2,154	240	296	72	920
70	9232	OUTSIDE SERVICE EMPL-LEGAL/FEE	1,870	3,004	6,213	594	2,003	2,388	1,760	7,494	3,133	3,057	1,344	3,530
71	9233	OUTSIDE AUDIT & ACCOUNTING FEE	26,628	26,135	26,135	28,345	25,413	25,323	26,460	26,460	55,188	31,773	26,991	(49,827)
72	924	PROPERTY INSURANCE	26,190	26,189	27,203	22,818	19,666	18,770	17,110	16,060	15,646	17,677	4,623	4,625
73	9251	INJURIES & DAMAGES	4,166	4,646	8,914	11,873	10,065	21,963	8,854	10,872	7,983	10,743	12,465	7,787
74	9252	GENERAL LIABILITY	43,489	44,529	46,738	50,191	82,599	241,823	51,434	52,467	102,112	49,774	46,016	207,221
75	9261	EMPLOYEE PENSIONS	40,938	43,111	104,187	63,083	62,174	30,684	59,809	63,031	24,621	59,374	61,118	61,548

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(13) Unadjusted Total	(14) Unadjusted Payroll	(15) Unadjusted Non-Payroll	(16) Payroll Adjustments	(17) Non-Payroll Adjustments	(18) Adjusted Payroll	(19) Adjusted Non-Payroll	(20) Adjusted Total
		CUSTOMER ACCOUNTS EXPENSES								
37	901	SUPERVISION	138,648	128,793	9,855	-	-	128,793	9,855	138,648
38	9011	SUPERVISION- A & G	66,195	-	66,195	-	-	-	66,195	66,195
39	902	METER READING EXPENSES	711,353	150,310	561,043	-	-	150,310	561,043	711,353
40	903	CUSTOMER RECORDS & COLLECTION	892,447	791,651	100,796	-	-	791,651	100,796	892,447
41	9031	CUST RECORDS/CLLCTN	476,926	-	476,926	-	-	-	476,926	476,926
42	904	UNCOLLECTIBLE ACCOUNTS	243,221	-	243,221	-	-	-	243,221	243,221
43	905	MISC CUSTOMER ACCOUNTS EXP	91,312	4,209	87,103	-	-	4,209	87,103	91,312
44	9051	MISC CUST ACCNT EXP	30,291	-	30,291	-	-	-	30,291	30,291
		CUSTOMER SERVICE & INFO								
45	9061	UNDERRECOVERY:CONSERVATION	-	-	-	-	-	-	-	-
46	907	SUPERVISION	142,210	117,183	25,027	(117,183)	(25,027)	-	-	-
47	908	CUSTOMER ASSISTANCE EXPENSE	1,279,693	392,420	887,273	(392,420)	(887,273)	-	-	-
48	909	INFO. & INSTRUCTIONAL ADVERTIS	839,999	601	839,398	(601)	(839,398)	-	-	-
49	910	MISC CUSTOMER SERVICE & INFO.	30,288	14,414	15,874	(14,414)	(15,874)	-	-	-
		SALES EXPENSES								
50	911	SUPERVISION	120,444	102,086	18,358	-	-	102,086	18,358	120,444
51	9121	SELLING EXPENSES	891,899	739,148	152,751	-	-	739,148	152,751	891,899
52	9122	DEMONSTRATING EXPENSES	38,099	33,685	4,414	-	-	33,685	4,414	38,099
53	9131	PROMOTIONAL ADVERTISING	54,102	-	54,102	-	-	-	54,102	54,102
54	9132	CONSERVATION ADVERTISING	23,100	-	23,100	-	(23,035)	-	65	65
55	9133	SAFETY ADVERTISING	41,058	-	41,058	-	-	-	41,058	41,058
56	9134	OTHER INFOR INSTRU CONS/ADVER	3,375	-	3,375	-	-	-	3,375	3,375
57	9135	COMMUNITY AFFAIRS ADVERTISING	-	-	-	-	-	-	-	-
58	9136	OTHER ADVERTISING	32,963	-	32,963	-	-	-	32,963	32,963
59	9161	MISC SALES EXP-PIP & CONV ALLW	435,639	-	435,639	-	-	-	435,639	435,639
60	9162	MISC SALES EXP-PROMO & OTHER	106,729	18,230	88,499	-	-	18,230	88,499	106,729
		ADMINISTRATIVE & GENERAL EXPENSES								
61	920	ADMINISTRATIVE & GEN SALARIES	1,309,028	1,299,432	9,596	-	-	1,299,432	9,596	1,309,028
62	9211	OFFICE SUPPLIES	20,859	-	20,859	-	-	-	20,859	20,859
63	9212	OFFICE POSTAGE & MAIL SUPPLIES	10,511	-	10,511	-	-	-	10,511	10,511
64	9213	OFF COMPUTER SUPPLIES & EXP	14,715	68	14,647	-	-	68	14,647	14,715
65	9214	OFFICE UTILITY EXPENSE	105,386	-	105,386	-	-	-	105,386	105,386
66	9215	MISC OFFICE EXPENSE	173,525	3,712	169,813	-	-	3,712	169,813	173,525
67	9216	CO TRAINING EXPENSE-TRACKED	3,870	-	3,870	-	-	-	3,870	3,870
68	922	ADMIN EXP TRANSFERRED-CREDIT	-	-	-	-	-	-	-	-
69	9231	OUTSIDE SERVICE - OTHER	6,701	-	6,701	-	-	-	6,701	6,701
70	9232	OUTSIDE SERVICE EMPL-LEGAL/FEE	36,390	-	36,390	-	-	-	36,390	36,390
71	9233	OUTSIDE AUDIT & ACCOUNTING FEE	275,024	-	275,024	-	-	-	275,024	275,024
72	924	PROPERTY INSURANCE	216,577	-	216,577	-	-	-	216,577	216,577
73	9251	INJURIES & DAMAGES	120,331	84,265	36,066	-	-	84,265	36,066	120,331
74	9252	GENERAL LIABILITY	1,018,393	(114,958)	1,133,351	-	-	(114,958)	1,133,351	1,018,393
75	9261	EMPLOYEE PENSIONS	673,678	(367,049)	1,040,727	-	-	(367,049)	1,040,727	673,678

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(1) Jan-07	(2) Feb-07	(3) Mar-07	(4) Apr-07	(5) May-07	(6) Jun-07	(7) Jul-07	(8) Aug-07	(9) Sep-07	(10) Oct-07	(11) Nov-07	(12) Dec-07
		ADMINISTRATIVE & GENERAL EXPENSES CONTINUED												
76	9262	EMPLOYEE BENEFITS- OTHER	76,943	70,731	64,474	71,652	72,260	35,164	66,007	62,188	72,496	64,067	67,743	83,807
77	9263	RETIREE BENEFITS-POST RETIREMT	8,500	8,667	8,667	8,667	8,667	8,667	8,667	8,667	8,667	8,667	8,667	(20,019)
78	9264	401(K) EXPENSE COMPA	1,477	2,070	3,017	2,051	2,303	2,317	2,888	5,030	3,242	3,200	3,408	5,644
79	9265	EMPLOYEE BENEFITS MEDICAL												
80	928	REGULATORY COMMISSION EXPENSES	11,092	8,936	8,680	8,477	11,131	6,617	7,397	8,881	19,462	8,508	3,807	9,164
81	9301	INSTITUTIONAL & GOODWILL ADVER	-	-	-	-	-	-	-	-	-	-	-	-
82	9302	MISC GENERAL EXPENSES	13,599	18,288	14,157	11,487	13,198	(3,869)	6,654	14,133	6,438	8,300	10,290	10,753
83	93022	INDUSTRY ASSOC DUES	1,051	7,734	-	-	4,033	-	19,608	-	3,785	-	-	-
84	93023	ECONOMIC DEVELOPMENT EXPENSES	-	-	-	-	-	-	-	-	-	-	-	-
85	931	RENTS	1,779	1,646	1,597	1,614	1,749	1,732	1,829	1,733	1,760	1,760	1,788	1,815
86		**TOTAL OPERATION EXPENSES**	1,268,598	1,239,155	1,464,450	1,437,571	1,373,464	1,612,047	1,270,232	1,339,139	1,374,701	1,360,198	1,327,314	1,442,893
87		**TOTAL OPERATION EXCL CONSV**	1,176,887	1,120,037	1,269,890	1,142,301	1,218,408	1,286,965	1,133,114	1,140,641	1,180,286	1,105,972	1,151,280	1,291,791
		MAINTENANCE EXPENSES												
		DISTRIBUTION EXPENSES												
88	885	MAINTNCE SUPERVI & ENGINEERING	9,596	9,509	9,264	10,062	11,430	5,291	8,277	8,980	7,978	9,060	8,618	9,526
89	886	MAINTNCE STRUCTURE & IMPROVEMT	5,663	5,888	20,347	11,255	17,213	8,366	5,879	14,987	2,641	9,951	4,851	6,635
90	887	MAINTENANCE OF MAINS	19,248	15,002	20,818	36,491	18,566	20,288	24,133	34,483	28,553	32,335	37,944	38,710
91	889	MAINT OF MEAS & REG STN-GENERL	601	153	601	(177)	1,542	662	511	2,116	4,298	2,017	2,618	1,117
92	890	MAINT OF MEAS & REG STN-INDUSL	-	-	-	-	-	-	-	-	-	-	-	-
93	891	MAINT-MEAS & REG STN-CTY GS CK	2,555	1,868	6,598	(238)	6,062	1,158	2,595	1,700	9,790	3,797	5,146	9,045
94	892	MAINTENANCE OF SERVICES	18,363	21,858	8,661	19,602	22,701	16,070	5,134	11,269	14,420	(1,328)	15,401	21,971
95	8931	MAINTENANCE OF METERS	14,465	9,825	12,063	8,610	7,624	10,639	6,892	6,963	4,431	18,460	6,314	4,614
96	8932	MAINTENANCE OF HOUSE REGULATOR	472	757	811	1,702	1,495	534	1,530	659	684	1,285	171	391
97	894	MAINTENANCE OF OTHER EQUIPMENT	609	576	426	546	194	508	220	889	1,727	348	2,682	2,877
		ADMINISTRATIVE & GENERAL EXPENSES												
98	935	MAINTENANCE OF GENERAL PLANT	24,998	14,712	17,205	(6,381)	9,505	14,581	15,757	24,993	10,402	12,821	12,616	10,524
99		**TOTAL MAINTENANCE EXPENSES**	96,570	80,148	96,794	81,472	96,332	78,097	70,928	107,039	84,924	88,746	96,361	105,410
100		**TOTAL O&M EXPENSES**	4,610,703	5,263,734	5,296,820	4,553,969	3,659,264	3,952,056	3,441,844	3,190,612	2,994,236	3,275,087	4,688,247	4,985,872
101		**TOTAL O&M EXCL CONSERVATION**	4,518,992	5,144,616	5,102,260	4,258,699	3,504,208	3,626,974	3,304,726	2,992,114	2,799,821	3,020,861	4,512,213	4,834,770
102		**TOTAL OPERATING EXPENSES O&M, GAS, UNBUND, CONSV**	4,611,201	5,264,212	5,297,783	4,554,259	3,661,248	3,952,047	3,442,062	3,190,875	2,994,613	3,275,522	4,688,343	4,986,349

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ACTUAL MONTHLY OPERATION AND MAINTENANCE EXPENSES BY PRIMARY ACCOUNT FOR THE HISTORIC YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	A/C NO.	DESCRIPTION	(13) Unadjusted Total	(14) Unadjusted Payroll	(15) Unadjusted Non-Payroll	(16) Payroll Adjustments	(17) Non-Payroll Adjustments	(18) Adjusted Payroll	(19) Adjusted Non-Payroll	(20) Adjusted Total
		ADMINISTRATIVE & GENERAL EXPENSES CONTINUED								
76	9262	EMPLOYEE BENEFITS- OTHER	807,532	(416,071)	1,223,603	47,656	-	(368,415)	1,223,603	855,188
77	9263	RETIREE BENEFITS-POST RETIREMT	75,151	-	75,151	-	-	-	75,151	75,151
78	9264	401(K) EXPENSE COMPA	36,647	(16,531)	53,178	-	-	(16,531)	53,178	36,647
79	9265	EMPLOYEE BENEFITS MEDICAL								
80	928	REGULATORY COMMISSION EXPENSES	112,152	2,588	109,564	-	-	2,588	109,564	112,152
81	9301	INSTITUTIONAL & GOODWILL ADVER	-	-	-	-	-	-	-	-
82	9302	MISC GENERAL EXPENSES	123,428	-	123,428	-	-	-	123,428	123,428
83	93022	INDUSTRY ASSOC DUES	36,211	-	36,211	-	-	-	36,211	36,211
84	93023	ECONOMIC DEVELOPMENT EXPENSES	-	-	-	-	-	-	-	-
85	931	RENTS	20,802	-	20,802	-	-	-	20,802	20,802
86		**TOTAL OPERATION EXPENSES**	16,509,762	5,933,022	10,576,740	(476,962)	(1,790,607)	5,456,060	8,786,134	14,242,193
87		**TOTAL OPERATION EXCL CONSV**	14,217,572	5,408,404	8,809,169	47,656	(23,035)	5,456,060	8,786,134	14,242,193
		MAINTENANCE EXPENSES								
		DISTRIBUTION EXPENSES								
88	885	MAINTNCE SUPERVI & ENGINEERING	107,591	92,127	15,464	-	-	92,127	15,464	107,591
89	886	MAINTNCE STRUCTURE & IMPROVEMT	113,676	34,159	79,517	-	-	34,159	79,517	113,676
90	887	MAINTENANCE OF MAINS	326,571	209,968	116,603	-	-	209,968	116,603	326,571
91	889	MAINT OF MEAS & REG STN-GENERL	16,059	8,106	7,953	-	-	8,106	7,953	16,059
92	890	MAINT OF MEAS & REG STN-INDUSL	-	-	-	-	-	-	-	-
93	891	MAINT-MEAS & REG STN-CTY GS CK	50,076	14,673	35,403	-	-	14,673	35,403	50,076
94	892	MAINTENANCE OF SERVICES	174,122	154,115	20,007	-	-	154,115	20,007	174,122
95	8931	MAINTENANCE OF METERS	110,900	82,356	28,544	-	-	82,356	28,544	110,900
96	8932	MAINTENANCE OF HOUSE REGULATOR	10,491	8,176	2,315	-	-	8,176	2,315	10,491
97	894	MAINTENANCE OF OTHER EQUIPMENT	11,602	3,956	7,646	-	-	3,956	7,646	11,602
		ADMINISTRATIVE & GENERAL EXPENSES								
98	935	MAINTENANCE OF GENERAL PLANT	161,733	2,015	159,718	-	-	2,015	159,718	161,733
99		**TOTAL MAINTENANCE EXPENSES**	1,082,821	609,651	473,170	-	-	609,651	473,170	1,082,821
100		**TOTAL O&M EXPENSES**	49,912,444	6,542,673	43,369,771	(476,962)	(34,110,468)	6,065,711	9,259,303	15,325,014
101		**TOTAL O&M EXCL CONSERVATION**	47,620,254	6,018,055	41,602,199	47,656	(32,342,896)	6,065,711	9,259,303	15,325,014
102		**TOTAL OPERATING EXPENSES O&M, GAS, UNBUND, CONSV**	49,918,514	6,546,089	43,372,425	(476,962)	(34,110,468)	6,069,127	9,261,957	15,331,084

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:PROVIDE A SCHEDULE DETAILING EXPENSES WHICH ARE SUBJECT TO ALLOCATION BETWEEN REGULATED AND NON-REGULATED OPERATIONS SHOWING GROSS AMOUNTS AND AMOUNTS ALLOCATED TO REGULATED EXPENSES AND A DETAILED DESCRIPTION OF ALLOCATION USED.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	DESCRIPTION	ACCOUNT NUMBERS	GROSS AMOUNT	ALLOCATED TO NON-REGULATED PERCENT	ALLOCATED TO NON-REGULATED AMOUNT	GAS REGULATED AMOUNT	OTHER REGULATED AMOUNT	DESCRIPTION OF ALLOCATION METHODS*
1	CUSTOMER ACCTS SUPERVISION	1849.901 & 9011	122,590	15.79%	19,352	66,199	37,040	Percentage of Customers
2	CUSTOMER RECORDS & COLL EXP	1840 / 1849.903 & 9031	882,834	15.85%	139,927	476,926	265,980	Percentage of Customers
3	MISC CUSTOMER ACCOUNTS EXP	1840 / 1849.905 & 9051	56,093	15.84%	8,883	30,290	16,920	Percentage of Customers
5	ADMINISTRATIVE/GENERAL SALARY	1840 / 1849.920 & 9201	2,562,372	8.91%	228,395	1,309,028	1,024,949	Percentage of Utility Plant
6	PROPERTY INSURANCE	1840.924	93,173	0.00%	-	53,032	40,140	Percentage of Utility Plant
7	MAINTENANCE -GENERAL PLANT	1840 / 1849.935	395,022	21.92%	86,569	196,502	111,951	Percentage of Common Plant
8	OFF SUPP/FURNISH.-EXEC. DEPT	1849.9211	45,055	27.86%	12,551	20,822	11,682	Percentage of Payroll
9	OFFICE POSTAGE & MAIL SUPPLIES	1840 / 1849.9212	22,051	25.89%	5,710	10,510	5,831	Percentage of Payroll
10	OFF COMPUTER SUPPLIES & EXPENS	1840 / 1849.9213	31,920	27.93%	8,916	14,715	8,288	Percentage of Payroll
11	OFFICE UTILITY EXPENSE	1849.9214	132,980	27.85%	37,035	61,471	34,475	Percentage of Payroll
12	MISC OFFICE EXPENSE	1840 / 1849.9215	375,688	27.83%	104,555	173,739	97,394	Percentage of Payroll
13	CO TRAIN.EXP-CORPORATE PROGRAM	1849.9216	8,265	26.85%	2,219	3,870	2,176	Percentage of Payroll
14	OUTSIDE SERVICE - OTHER	1849.9231	13,084	17.60%	2,302	6,699	4,082	Percentage of Adjusted Gross Profit
15	OUTSIDE SERVIC-LEGAL FEE & EXP	1840 / 1849.9232	70,795	17.90%	12,671	36,141	21,982	Percentage of Adjusted Gross Profit
16	OUTSIDE AUDIT & ACCOUNTING FEE	1849.9233	510,721	17.81%	90,960	260,953	158,809	Percentage of Adjusted Gross Profit
17	SAFETY	1840 / 1849.9251	162,919	17.90%	29,166	83,169	50,585	Percentage of Adjusted Gross Profit
18	GENERAL LIABILITY	1840 / 1849.9252	1,301,107	0.00%	30	806,275	494,802	Percentage of Adjusted Gross Profit
19	EMPLOYEE PENSIONS	1840.9261	1,403,991	0.00%	-	925,822	478,169	Percentage of Payroll
20	EMPLOYEE BEN-MEDICAL & OTHER	1840 / 1849.9262	1,608,276	1.45%	23,312	1,044,557	540,407	Percentage of Payroll
21	CONSOL-RET BENIF-POST RETIRE	1849.9263	200,000	21.08%	42,167	103,833	54,000	Percentage of Payroll
22	401(K) EXPENSE COMPANY MATCH	1840 / 1849.9264	72,098	0.00%	-	47,556	24,542	Percentage of Payroll
23	MISCELLANEOUS GENERAL EXPENSES	1840 / 1849.9302	216,256	11.37%	24,596	120,387	71,273	Percentage of Adjusted Gross Profit
24	INDUSTRY ASSOCIATION DUES	1849.93022	625	16.82%	105	322	197	Percentage of Adjusted Gross Profit
25	COMMON DEPRECIATION	4030.2	381,120	21.50%	81,953	193,774	105,393	Percentage of Common Plant
	TOTAL		10,669,035		961,376	6,046,593	3,661,066	

* ALLOCATION METHODS ARE EXPLAINED ON G-6 PAGE 4 AND 5

* ATTACH ADDITIONAL PAGES AS NEEDED TO FULLY EXPLAIN ALLOCATION METHODS.

SUPPORTING SCHEDULES: G-6 page 4 and 5

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE ITEMIZING REVENUES REPORTED PURSUANT TO RULE 25-17.015 AND EXPENSES INCURRED PURSUANT TO THE COMMISSION PRESCRIBED CONSERVATION GOALS.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

LINE NO.	ACCT. NO.	SUB ACCT.	DESCRIPTION	AMOUNT
			REVENUES	
1	4000	48005	RES	1,067,161
2	4000	48105	CS	462,828
3	4000	48115	CL	494,189
4	4000	48125	INT	-
5	4000	48905	TRANS CS	38,408
6	4000	48915	TRANS CL	330,874
7	4000	48925	TRANS INT	-
8	4000	48935	TRANS LV INT	-
9	4000	48135	LAKE WORTH	-
10	4000	48405	INTERDEPARTMENTAL	-
11	4000	48985	POOL	-
12	4000	48145	OUTDOOR LIGHTS	-
13	4000	49545	OSS	-
14			TOTAL ENERGY CONSERVATION REVENUES	2,393,460
			EXPENSES	
15	4010	9061	UNDERRECOVERY:CONSERVATION	-
16	4010	907-910	GoodCents Home (New Construction)	300,624
17	4010	907-910	Residential Appliance Replacement	662,858
18	4010	907-910	GoodCents Conservation Education	58,810
19	4010	907-910	GoodCents Space Conditioning	12,272
20	4010	907-910	GoodCents Energy Survey (Residential)	51,910
21	4010	907-910	GoodCents Appliance Upgrade	551,109
22	4010	907-910	GoodCents Dealer / Contractor	3,690
23	4010	907-910	GoodCents Commercial Energy Survey	64,034
24	4010	907-910	Commercial Equipment Repair	-
25	4010	907-910	Residential Service Reactivation	36,053
26	4010	907-910	Common	550,827
27			TOTAL ENERGY CONSERVATION EXPENSES	2,292,187

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE ITEMIZING REVENUES REPORTED DUE TO PGA AND ASSOCIATED EXPENSES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	ACCT. NO.	SUB ACCT.	DESCRIPTION	AMOUNT
			REVENUES	
1	4000	48002	Residential	8,972,620
2	4000	48102	Commercial Small	8,844,388
3	4000	48112	Commercial Large	13,328,157
4	4000	48122	Interruptible	103,304
5	4000	48902	TRANS CS	-
6	4000	48912	TRANS CL	-
7	4000	48922	TRANS INT	-
8	4000	48932	TRANS LV INT	-
9	4000	49552	LAKE WORTH	-
10	4000	48402	INTERDEPARTMENTAL	50,045
11	4000	48982	Pool	(1,429,484)
12	4000	48142	OUTDOOR LIGHTS	148,432
13	4000	49542	Customer - Off System Sales	-
14			TOTAL PGA REVENUES	30,017,462
15				
16				
17				
18				
19				
20				
21				
22			**EXPENSES**	
23				
24	4010	8051	UNDER RECOVERY PURCHASED GAS	-
25				
26				
27				
28				
29	4010	8011	COMMODITY OTHER-SYSTEM SUPPLY	28,000,983
30	4010	8041	DEMAND/RESERV CHG-PIPE PURCH	-
31	4010	8042	COMMODITY PIPELINE-SYSTEM SUPP	525,067
32	4010	8045	DEMAND SYSTEM SUPPLY	3,786,209
33	4010	80472	COMMODITY PIPELINE - TRANS	-
34	4010	80473	DEMAND TRASPORTATION	-
35	4010	80491	COMMODITY OTHER OFF SYSTEM SAL	-
36	4010	80492	COMMODITY PIPELINE - OFFSYSTEM	-
37	4010	80493	DEMAND - OFF SYSTEM SALES	-
38	4010	8051	UNDER RECOVERY PURCHASED GAS	-
39	4010	8073	PURCHASED GAS CALCULATION EXP	-
40	4010	8074	OTHER PURCHASED GAS EXPENSE	-
41	4010	8075	PURCHASED GAS EXPENSE	7,602
42				
43			**TOTAL PGA EXPENSES**	32,319,861
44				
45				

SCHEDULE C-8	UNCOLLECTIBLE ACCOUNTS	PAGE 1 OF 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	EXPLANATION: PROVIDE A SCHEDULE OF BALANCE SHEET ACCOUNTS FOR THE PROVISION OF UNCOLLECTIBLE ACCOUNTS BY MONTH FOR THE HISTORIC BASE YEAR AND 2 PRIOR YEARS.	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/2007 PRIOR YEAR ENDED: 12/31/2006 PRIOR YEAR ENDED: 12/31/2005 WITNESS: LUNDGREN

	LINE NO.	ACCOUNT 1440.1	BEGINNING BALANCE	BAD DEBT WRITE OFFS	PROVISION ACCRUAL	RECOVERIES & ADJUSTMENTS	COVERED BY CUSTOMER DEPOSIT**	ENDING BALANCE
HISTORIC YEAR: 2007	1	Dec-07	(210,509)	37,628	(20,442)	(5,086)	-	(198,409)
	2	Nov-07	(211,367)	23,042	(17,182)	(5,002)	-	(210,509)
	3	Oct-07	(218,221)	26,697	(14,248)	(5,595)	-	(211,367)
	4	Sep-07	(240,765)	36,714	(12,304)	(1,866)	-	(218,221)
	5	Aug-07	(233,304)	15,889	(17,252)	(6,098)	-	(240,765)
	6	Jul-07	(245,493)	29,078	(12,264)	(4,625)	-	(233,304)
	7	Jun-07	(232,580)	18,214	(28,339)	(2,788)	-	(245,493)
	8	May-07	(229,704)	19,769	(18,689)	(3,956)	-	(232,580)
	9	Apr-07	(230,716)	25,086	(22,584)	(1,490)	-	(229,704)
	10	Mar-07	(214,790)	14,792	(27,479)	(3,239)	-	(230,716)
	11	Feb-07	(203,152)	20,629	(25,805)	(6,462)	-	(214,790)
	12	Jan-07	(188,388)	18,379	(26,633)	(6,510)	-	(203,152)
	13							
	14	TOTAL	(188,388)	285,917	(243,221)	(52,717)	-	(198,409)
	15							
	16							
PRIOR YEAR: 2006	17	Dec-06	(180,804)	27,719	(28,835)	(6,468)		(188,388)
	18	Nov-06	(179,953)	23,900	(17,993)	(6,758)		(180,804)
	19	Oct-06	(164,949)	19,131	(30,683)	(3,452)		(179,953)
	20	Sep-06	(71,452)	42,040	(130,651)	(4,886)		(164,949)
	21	Aug-06	(78,563)	22,772	(10,151)	(5,510)		(71,452)
	22	Jul-06	(88,026)	25,167	(10,768)	(4,936)		(78,563)
	23	Jun-06	(141,585)	40,300	19,842	(6,583)		(88,026)
	24	May-06	(158,262)	35,141	(13,547)	(4,917)		(141,585)
	25	Apr-06	(172,905)	33,110	(15,873)	(2,594)		(158,262)
	26	Mar-06	(183,753)	35,011	(22,835)	(1,328)		(172,905)
	27	Feb-06	(180,729)	26,220	(25,009)	(4,235)		(183,753)
	28	Jan-06	(168,581)	18,014	(25,651)	(4,511)		(180,729)
	29							
	30	TOTAL	(168,581)	348,525	(312,154)	(56,178)	-	(188,388)
	31							
	32							
PRIOR YEAR: 2005	33	Dec-05	(143,714)	52,063	(72,277)	(4,653)		(168,581)
	34	Nov-05	(123,021)	-	(18,503)	(2,190)		(143,714)
	35	Oct-05	(104,613)	-	(15,634)	(2,774)		(123,021)
	36	Sep-05	(121,185)	31,904	(12,878)	(2,454)		(104,613)
	37	Aug-05	(131,218)	24,109	(11,904)	(2,172)		(121,185)
	38	Jul-05	(141,556)	24,471	(12,203)	(1,930)		(131,218)
	39	Jun-05	(155,493)	27,559	(12,042)	(1,580)		(141,556)
	40	May-05	(159,517)	20,215	(14,927)	(1,264)		(155,493)
	41	Apr-05	(156,286)	15,078	(16,726)	(1,583)		(159,517)
	42	Mar-05	(142,017)	6,275	(18,976)	(1,568)		(156,286)
	43	Feb-05	(127,422)	10,074	(21,800)	(2,869)		(142,017)
	44	Jan-05	(116,603)	12,203	(21,331)	(1,691)		(127,422)
	45							
	46	TOTAL	(116,603)	223,951	(249,201)	(26,728)	-	(168,581)

** Bad bebt amounts do not include amounts covered by customer deposits. If an account was covered by customer deposits, it would not have been recorded as bad debt.

SUPPORTING SCHEDULES: B-1 page 1, B-13

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF ADVERTISING EXPENSES BY SUB-ACCOUNT FOR THE HISTORIC BASE YEAR AND PRIOR YEAR FOR EACH TYPE OF ADVERTISING.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
PRIOR YEAR ENDED: 2006
WITNESS: LUNDGREN

		ADVERTISING EXPENSES PRIOR YEAR ENDED **DECEMBER 2006**		ADVERTISING EXPENSES HISTORIC YEAR ENDED **DECEMBER 2007**	
ACCOUNT NO.	ACCOUNT TITLE	TOTAL PER BOOKS	JURISDICTIONAL AMOUNT	TOTAL PER BOOKS	JURISDICTIONAL AMOUNT
9131	PROMOTIONAL ADVERTISING	55,827	55,827	54,102	54,102
9132	CONSERVATION ADVERTISING	5,250	5,250	23,100	23,100
9133	SAFETY ADVERTISING	41,447	41,447	41,058	41,058
9134	OTHER INFOR INSTRU CONS/ADVER	8,002	8,002	3,375	3,375
9135	COMMUNITY AFFAIRS ADVERTISING	8,340	8,340	-	-
9136	OTHER ADVERTISING	39,994	39,994	32,963	32,963
	TOTAL ADVERTISING EXPENSE	158,860	158,860	154,598	154,598

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-5 p.3 & 4

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF CIVIC AND CHARITABLE CONTRIBUTIONS INCLUDED IN NET OPERATING INCOME FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	DESCRIPTION	FPUC TOTAL	AMOUNT ALLOCATED TO GAS	AMOUNT REGULATED
	NONE			

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

SCHEDULE C-11	INDUSTRY ASSOCIATION DUES	PAGE 1 OF 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	EXPLANATION:PROVIDE A SCHEDULE OF INDUSTRY ASSOCIATION DUES INCLUDED IN NET OPERATING INCOME BY ORGANIZATION FOR THE HISTORIC YEAR ENDED 12/31/07	TYPE OF DATA SHOWN: HISTORICAL HISTORIC YEAR ENDED: 12/31/2007 WITNESS: LUNDGREN

LINE NO.	ORGANIZATION		AMOUNT	% ALLOCATED TO NATURAL GAS	ALLOCATED TO NATURAL GAS
	NATURAL GAS				
1	FASB		370	52%	192
2	Associated Gas Distributors of FL		6,600	13% *	860
3	Southern Gas Association		7,734	100%	7,734
4	Associated Gas Distributors of FL		6,600	59%	3,903
5	Florida Institute for Certified Public Accountants		255	51%	130
6	FNGA		28,010	70%	19,607
7	Associated Gas Distributors of FL		6,400	59%	3,785
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	TOTAL	ACCOUNT 9302	55,969		36,211

* $3,044.51 of this invoice was allocated to 121.4010.9302 (instead of 121.4010.93022)

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-5 p. 5

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE, BY ORGANIZATION, OF EXPENSES FOR LOBBYING, CIVIC, POLITICAL AND RELATED ACTIVITIES INCLUDED IN NET OPERATING INCOME FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	ACCOUNT	ORGANIZATION		AMOUNT
		NONE		

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-5 p.2

SCHEDULE C-13

TOTAL RATE CASE EXPENSE AND COMPARISONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A COMPARISON OF RATE CASE EXPENSES INCURRED OR ANTICIPATED FOR THE CURRENT AND MOST RECENT PRIOR CASE WITH EXPLANATION OF ANY CHANGES WHICH EXCEED 10% ON AN INDIVIDUAL ITEM BASIS. ALSO PROVIDE AN AMORTIZATION SCHEDULE OF RATE CASE EXPENSE AS A PERCENTAGE OF RATE BASE AND OPERATING REVENUES AND THE AMOUNT PER CUSTOMER

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
PRIOR RATE CASE: 2004

WITNESS: MARTIN

COMPARISON OF CURRENT RATE CASE EXPENSES WITH PRIOR CASE

LINE NO.	DESCRIPTION	PRIOR CASE 04/05	CURRENT CASE 08/09	PERCENT CHANGE (TOTAL)	PERCENT CHANGE (ANNUAL)	REASON FOR CHANGE (IF 10% OR GREATER)
1	OUTSIDE CONSULTANTS	219,100	408,250	86.33%	16.8345%	It has been four years since our last rate proceeding, so costs have increased with inflation and other factors; in addition, we are utilizing the Consultants for additional services due to the work demands and work loads of the FPUC staff. Additional services and expertise is required to complete a rate proceeding.
2	LEGAL SERVICES	33,941	107,500	216.73%	33.4%	The prior rate case did not go to full hearing. In addition, costs have increased with inflation and other factors. Some of the issues are more complex and require additonal testimony and support, increasing the overall complexity of the case.
3	TRAVEL EXPENSES	4,336	34,080	685.98%	67.4%	It has been four years since our last rate proceeding, and costs have increased with inflation and other related factors such as gasoline costs. We anticipate the need for additional meetings in Tallahassee and WPB over the prior rate proceeding due to complexity of some of the issues.
4	PAID OVERTIME / TEMP PAY	48,248	207,000	329.03%	43.9%	The work load has increased within the accounting department, and the Company has to utilize additional temporary staff and overtime by current personnel to absorb the workload required by a rate proceeding. The Company is not staffed at a level to allow for preparation of a proceeding without the use of additional resources.
5	OTHER EXPENSES	38,351	87,250	127.50%	22.8%	We anticipate additional notices may be required in this proceeding over the last proceeding to keep our customers informed. Also, the cost of paper and other supplies have increased.
	TOTAL	343,976	844,080	145.39%	25.2%	

SCHEDULE OF RATE CASE AMORTIZATION IN THE HISTORIC BASE YEAR

LINE NO.	DESCRIPTION	TOTAL EXPENSES	RATE ORDER AMORTIZATION DATE	RATE ORDER AMORTIZATION PERIOD	AMORTIZED AMOUNT 2004-2008	2009	2010	2011	2012	2013	2014	UNAMORTIZED BALANCE
6	PRIOR CASE: DOCKET NO. 040216-GU	343,976	11/8/2004	4YEARS	343,976	-	-					-
7	CURRENT CASE: DOCKET NO. 080366-GU	844,080		4 YEARS	-	123,095	211,020	211,020	211,020	87,925	-	-
8	TOTAL	1,188,056			343,976	123,095	211,020	211,020	211,020	87,925	-	-

LINE NO.	DESCRIPTION			2004 DOCKET NO. 040216-GU	2008 DOCKET NO. 080366-GU		
9	RATE CASE EXPENSE INCURRED (ANTICIPATED) AS A PERCENTAGE OF RATE BASE	2007 HISTORIC YEAR =	59,518,973	0.5779%	1.4182%	2007 HISTORIC YEAR =	59,518,973
10	RATE CASE EXPENSE INCURRED (ANTICIPATED) AS A PERCENTAGE OF REVENUE	2007 HISTORIC YEAR =	29,731,612	1.1569%	2.8390%	2007 HISTORIC YEAR =	29,731,612
11	RATE CASE EXPENSE INCURRED (ANTICIPATED) PER CUSTOMER	2007 HISTORIC YEAR =	49,207	$6.99	$17.15	2007 HISTORIC YEAR =	49,207

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-5

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE BY TYPE OF CHARGE, OF THE CHARGES TO ACCOUNT 930 (MISCELLANEOUS GENERAL EXPENSES) FOR THE HISTORIC BASE YEAR. PROVIDE ALSO THE AMOUNT ALLOCATED TO UTILITY OPERATIONS.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

MISCELLANEOUS GENERAL EXPENSES FOR THE 12 MONTHS ENDED 12/31/2007

LINE NO.	ACCOUNT	DESCRIPTION	2007 TOTAL	NATURAL GAS AMOUNT
1	9302	Publishing and Distributing Information and Reports to Stockholders: Trustees, Registrar, and Transfer Agent Fees and Expense, and Other Expenses of Servicing Outstanding Securities of the Respondent	56,535	28,833
2	9302	Director fees and expenses	148,976	75,978
3	9302	Annual Report printing and mailing	8,127	5,039
4	9302	Banking fees	9,020	4,600
5	9302	Miscellaneous Expenses	11,633	5,933
6	9302	Membership Dues & Subscriptions Assoc. Gas Distr. Of Fl.	3,045	3,045
7	93022	Membership Dues & Subscriptions	41,644	36,211
8	92023	Economic Development Expense	5,000	0
		TOTAL - 930	$283,980	$159,639

Detail:

Stock Transfer Agent	12,389
Amer. Stock Exchange Listing	9,690
Annual Stockholder Meeting	5,063
Press Releases	1,691
Total	28,833
Directors - Cash Retainers	26,701
Directors - Stock Retainers	24,797
Directors - Meetings	24,480
Total	75,978
Florida Natural Gas Assoc.	19,607
Southern Gas Assoc.	7,734
Associated Gas Distributors of Fl	8,547
Accounting Assoc. (2)	323
Total	36,211

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A LIST OF OUT OF PERIOD ITEMS FOR THE HISTORIC BASE YEAR AND THE RELATED ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES BY PRIMARY ACCOUNT.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

LINE NO.	ACCOUNT NO.	ACCOUNT TITLE	(1) DESCRIPTION	(2) DATE INCURRED	(3) DEBIT	(4) CREDIT

ALL ADJUSTMENTS ARE DESCRIBED ON C-2, * ARE OUT OF PERIOD ADJUSTMENTS

* FEDERAL INCOME TAX PRIOR PERIOD ADJUSTMENTS
* STATE INCOME TAX PRIOR PERIOD ADJUSTMENTS
* FEDERAL DEFERRED INCOME TAX PRIOR PERIOD ADJUSTMENTS
* STATE DEFERRED INCOME TAX PRIOR PERIOD ADJUSTMENTS

PGA EXPENSES
OVER/UNDER REC PGA
CONSERVATION EXPENSES
OVER/UNDER REC CONS
AEP EXPENSES
* OVER EARNINGS ADJUSTMENTS
NON-UTILITY DEPRECIATION ADJUSTMENT

* CONSERVATION RELATED ADJUSTMENTS FROM AUDITS

SUPPORTING SCHEDULES: | RECAP SCHEDULES: C-2

SCHEDULE C-16 GAINS AND LOSSES ON DISPOSITION OF PLANT OR PROPERTY

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF GAINS AND LOSSES ON DISPOSITION OF PROPERTY PREVIOUSLY USED IN PROVIDING GAS SERVICE FOR THE HISTORIC BASE YEAR AND FOUR PRIOR YEARS. LIST AMOUNTS ALLOWED IN PRIOR RATE CASES, AND THE HISTORIC YEAR OF SUCH PRIOR CASES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007

WITNESS: Mesite

(1) (2) DESCRIPTION OF PROPERTY	(4) DATE ACQUIRED	(5) DATE DISPOSED	(7) ORIGINAL CLASSIFICATION	(8) RECLASS. ACCOUNT	(9) ORIGINAL AMOUNT RECORDED	(10) ADDITIONS OR RETIREMENTS	(11) NET BOOK VALUE ON DISPOSAL DATE	(12) GAIN OR LOSS	(13) REGULATED GAIN OR LOSS	(14) AMOUNT ALLOWED PRIOR CASE @ 1/1/05	(15) PRIOR CASE'S TEST YEAR ENDED
Building and Land	July 1982	March 2002	1010.389 & .390	2530.4	62,506	25,031	87,537	528,748	444,148	199,746	12/31/05
325 N.E. 2nd St.											
Delray Beach, FL											
Parcel #12-43-46-16-47-000-0100											
Satellite Bill Paying Location											
Amortization over 5 years											
Amortization per Order No. PSC-02-1159-PAA-GU											
Included in Previous Rate Case 040216-GU											
Building and Land	June 1967	July 2002	1010.389 & .390	2530.4	12,158	170,576	182,735	186,110	158,194	81,747	12/31/2005
Corner of Berresford Ave.											
and Florida Ave.											
Deland, FL											
Parcel # 7009-01-770030											
Former Operation Center in South Florida											
Amortization over 5 years											
Amortization per Order No. PSC-02-1727-PAA-GU											
Included in Previous Rate Case 040216-GU											
TOTAL					74,664	195,607	270,272	714,858	602,342	281,493	

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE MONTHLY DEPRECIATION EXPENSE FOR EACH ACCOUNT OR SUB-ACCOUNT TO WHICH AN INDIVIDUAL DEPRECIATION RATE IS APPLIED.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

WITNESS: Mesite

	(1) Acct 1180	(2) DESCRIPTION	(3) % RATE	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) TOTAL DEPR
1	303	MISC. INTANGIBLE PLANT	29 Yrs.	605	605	605	605	605	605	605	605	605	605	605	605	7,260
2	3741	LAND RIGHTS	3.2%	34	34	34	34	34	34	34	34	34	34	34	34	408
3	375	STRUCTURES AND IMPROVEMENTS	2.8%	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	13,356
4	3761	MAINS- PLASTIC	2.6%	47,442	47,716	48,414	48,750	48,942	49,296	50,241	51,255	51,535	52,270	52,610	54,625	603,096
5	3762	MAINS -OTHER-(CAST IRON, STEEL)	2.6%	58,817	58,815	58,822	58,844	58,764	58,753	58,750	58,654	58,656	58,650	58,651	58,616	704,792
6	378	MEASURE/REGULATOR EQP.-GENERAL	3.4%	868	868	868	868	868	868	868	868	868	868	868	868	10,416
7	379	MEASURE/REG EQP - CITY GATE STN	3.5%	5,874	5,874	5,874	5,874	5,874	5,874	5,874	5,874	5,874	5,874	5,874	5,884	70,498
8	3801	SERVICES - PLASTIC	3.2%	52,898	53,285	53,620	53,862	54,133	54,356	54,688	54,991	55,357	55,645	55,976	58,377	657,188
9	3802	SERVICES - OTHER- CAST IRON, ETC	7.5%	13,610	13,610	13,610	13,557	13,534	13,500	13,488	13,471	13,458	13,449	13,430	13,427	162,144
10	381	METERS	3.3%	15,301	15,330	15,302	15,290	15,250	15,517	15,398	15,284	15,269	15,422	15,508	15,648	184,519
11	382	METER INSTALLATIONS	3.0%	6,109	6,150	6,187	6,245	6,274	6,504	6,564	6,709	6,753	6,816	6,843	7,104	78,258
12	383	HOUSE REGULATORS	3.5%	5,062	5,062	5,280	5,289	5,285	5,286	5,281	5,293	5,543	5,622	5,687	5,718	64,408
13	384	HOUSE REGULATOR INSTALLATIONS	3.4%	2,429	2,439	2,448	2,454	2,462	2,467	2,477	2,483	2,515	2,525	2,533	2,562	29,794
14	385	INDUST MEASURING/REG STATION EQP	3.3%	133	133	133	133	133	133	133	133	133	133	133	136	1,599
15	387	OTHER EQUIPMENT	3.7%	1,625	1,641	1,666	1,669	1,690	1,706	1,719	1,721	1,725	1,725	1,725	1,733	20,345
16	390	STRUCTURES AND IMPROVEMENTS	2.5%	2,905	2,905	2,905	2,915	2,915	2,915	2,915	2,920	2,952	2,953	2,925	2,925	35,050
17	3911	OFFICE FURNITURE	4.8%	440	440	440	452	452	452	452	452	452	442	442	442	5,358
18	3912	OFFICE MACHINES	7.5%	247	247	247	293	293	293	293	293	293	293	415	415	3,622
19	3913	E D P EQUIPMENT	11.1%	5,374	5,374	5,374	5,339	5,324	5,313	5,597	5,729	5,710	5,625	5,607	5,687	66,053
20	391305	COMPUTER SOFTWARE	11.1%	4,481	4,481	4,497	4,497	4,839	4,894	4,894	4,894	4,894	4,894	4,894	4,894	57,053
21	3921	TRANSP EQUIP-CARS	11.3%													-
22	3922	TRANS - LIGHT TRUCK, VAN	8.2%													-
23	3923	TRANS - HEAVY TRUCKS	0.0%													-
24	3924	TRANS - TRAILERS	5.8%													-
25	393	STORES EQUIPMENT	4.6%	37	37	37	37	37	37	37	37	37	37	37	37	444
26	394	TOOLS, SHOP & GARAGE EQUIPMENT	6.6%	1,557	1,559	1,559	1,668	1,645	1,696	1,696	1,704	1,717	1,671	1,671	1,742	19,885
26	395	LABORATORY EQUIPMENT	2.2%	-	-	-	-	-	-	-	-	-	-	-	-	-
27	396	POWER OPERATED EQUIPMENT	6.3%	1,722	1,722	1,722	1,722	1,722	1,722	1,722	1,748	1,748	1,748	1,748	1,693	20,739
28	397	COMMUNICATION EQUIPMENT	7.8%	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,760	1,760	1,760	1,760	1,448	20,752
29	398	MISCELLANEOUS EQUIPMENT	6.0%	723	723	723	723	723	723	723	723	723	773	750	750	8,780
30		TOTAL		231,158	231,915	233,232	233,985	234,663	235,809	237,314	238,748	239,724	240,947	241,839	246,483	2,845,817
31																
32	2530.4	Amortize Deferred Gains		(10,035)	(10,035)	(10,035)	(2,637)	(2,637)	(2,637)	(2,637)	-	-	-	-	-	(40,653)
33		NET DEPRECIATION EXPENSE		221,123	221,880	223,197	231,348	232,026	233,172	234,677	238,748	239,724	240,947	241,839	246,483	2,805,164

Note: Rates Per Docket No. 040352-GU, Order No. PSC-04-1045-PAA-GU

SUPPORTING SCHEDULES: B-5, C-16

RECAP SCHEDULES: C-1

SCHEDULE C-18 | AMORTIZATION/RECOVERY SCHEDULE FOR THE HISTORIC BASE YEAR - 12 MONTHS |

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE FOR EACH AMORTIZATION/RECOVERY INCLUDED IN PLANT IN SERVICE BY ACCOUNT OR SUB-ACCOUNT FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN: HISTORIC YEAR - 12/31/07

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO: 080366-GU

(1) Acct	(2) DESCRIPTION	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) TOTAL DEPR
4050.1	AMORTIZATION - ENVIRONMENTAL													
	S/L 3500, Manufactured Gas Plant Site - Sanford	3,694	3,694	3,694	3,694	3,694	3,694	3,694	3,694	3,694	3,694	3,694	3,694	44,328
	S/L 3510, Manufactured Gas Plant Site - Deland	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(359)	(4,308)
	S/L 3590, Manufactured Gas Plant Site - Pensacola	417	417	417	417	417	417	417	417	417	417	417	417	5,004
	S/L 3600, Manufactured Gas Plant Site - Key West	351	351	351	351	351	351	351	351	351	351	351	351	4,212
	S/L 3690, Manufactured Gas Plant Site Litigation - Sanford	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	2,340	28,080
	S/L 3730, Manufactured Gas Plant Insurance Carrier-Sanford	2,070	2,070	2,070	2,070	2,070	2,070	2,070	2,070	2,070	2,070	2,070	2,070	24,840
	S/L 3760, Manufactured Gas Plant Site - West Palm Beach	29,516	29,516	29,516	29,516	29,516	29,516	29,516	29,516	29,516	29,516	29,516	29,516	354,192
		38,029	38,029	38,029	38,029	38,029	38,029	38,029	38,029	38,029	38,029	38,029	38,029	456,348
	AMORTIZATION/RECOVERY PERIOD:	20 Years		EFFECTIVE DATE:		2004		AMORTIZATION/RECOVERY:			$ 456,348			
	REASON:	2003 NATURAL GAS RATE PROCEEDING, DOCKET NO. 040216-GU												
4060.1	AMORTIZATION OF ACQUISITION ADJUSTMENT													
	Atlantis	13	13	13	13	13	13	13	13	13	13	13	13	156
	University Park	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(55)	(660)
	North Palm Beach	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(456)
	SFNG Acquisition	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	32,016
	TOTAL	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	31,056
	AMORTIZATION/RECOVERY PERIOD:	30 Years		EFFECTIVE DATE:		Various		AMORTIZATION/RECOVERY:			$ 31,056			
	REASON:	2003 NATURAL GAS RATE PROCEEDING, DOCKET NO. 040216-GU												
4070.3	Bare Steel Replacement Program	47,193	47,193	47,193	47,193	47,193	47,193	47,193	47,193	47,193	47,193	47,193	47,193	566,316
	AMORTIZATION/RECOVERY PERIOD:	50 Years		EFFECTIVE DATE:		2004		AMORTIZATION/RECOVERY:			$ 566,316			
	REASON:	2003 NATURAL GAS RATE PROCEEDING, DOCKET NO. 040216-GU												
4070.5	AMORTIZATION OF AEP - EXCESS MACC, AMORTIZATION SCHEDULE	58,387	70,251	67,348	50,934	35,627	35,266	29,953	27,709	28,744	30,140	33,329	47,086	514,774
	AMORTIZATION/RECOVERY PERIOD:	10 Years		EFFECTIVE DATE:		1995		AMORTIZATION/RECOVERY:			$ 514,774			
	REASON:	2003 NATURAL GAS RATE PROCEEDING, DOCKET NO. 040216-GU												
	TOTAL AMORTIZATION	146,197	158,061	155,158	138,744	123,437	123,076	117,763	115,519	116,554	117,950	121,139	134,896	1,568,494
	COMMISSION ADJUSTMENTS TO AMORTIZATION - SEE DIRECT TESTIMONY OF JAMES V. MESITE, JR.													
4070.5	ELIMINATION AMORTIZATION OF AEP - EXCESS MACC, AMORTIZATION	(58,387)	(70,251)	(67,348)	(50,934)	(35,627)	(35,266)	(29,953)	(27,709)	(28,744)	(30,140)	(33,329)	(47,086)	(514,774)
	REASON:	ELIMINATION OF AMORTIZATION						2003 NATURAL GAS RATE PROCEEDING, DOCKET NO. 040216-GU						

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A SCHEDULE SHOWING THE ALLOCATION OF DEPRECIATION AND AMORTIZATION EXPENSE FOR THE HISTORIC BASE YEAR. THIS DATA SHOULD CORRESPOND TO THE DATA PRESENTED IN SCHEDULE B-11.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION

WITNESS: Mesite

DOCKET NO.: 080366-GU

Line	(1)	(2) DESCRIPTION	(3) % RATE	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) TOTAL DEPR
1	390	STRUCTURES AND IMPROVEMENTS	2.5%	4,404	4,406	4,406	4,406	4,505	4,505	4,505	4,505	4,511	4,518	4,518	4,522	53,711
2	3911	OFFICE FURNITURE	4.8%	152	152	152	152	152	152	152	152	152	152	152	152	1,824
3	3912	OFFICE MACHINES	7.5%	890	890	890	890	890	884	899	899	899	915	793	793	10,532
4	3913	E D P EQUIPMENT	11.1%	4,552	4,552	4,552	5,374	5,380	6,692	7,065	6,869	6,888	6,921	6,904	6,702	72,451
5	391305	COMPUTER SOFTWARE	11.1%	15,883	15,883	15,890	16,211	16,211	16,222	16,240	16,240	16,301	16,301	16,301	16,301	193,984
6	3921	TRANSP EQUIP-CARS	11.3%	792	792	792	792	792	792	792	792	792	792	792	792	9,504
7	3922	TRANS-LIGHT TRUCK, VAN	8.2%	852	852	852	852	852	852	852	852	852	852	852	852	10,224
8	397	COMMUNICATION EQUIPMENT	5.8%	760	760	760	760	760	760	760	760	760	760	760	760	9,120
9	398	MISCELLANEOUS EQUIPMENT	4.6%	34	34	34	34	34	34	49	49	49	49	49	49	498
10	399	TANGIBLE PROPERTY	20.0%	1,693	383	383	383	383	383	383	383	383	383	383	383	5,904
11		TOTAL		30,012	28,704	28,711	29,854	29,959	31,276	31,697	31,501	31,587	31,643	31,504	31,306	367,752
12																

Line	(1)	(2) DESCRIPTION	(3) % RATE	(4) JAN. '07	(5) FEB. '07	(6) MAR. '07	(7) APR. '07	(8) MAY. '07	(9) JUN. '07	(10) JUL. '07	(11) AUG. '07	(12) SEP. '07	(13) OCT. '07	(14) NOV. '07	(15) DEC. '07	(16) TOTAL DEPR
15		ALLOCATED TO NATURAL GAS - SEE BELOW FOR ALLOCATION PERCENTAGES														
16	390	STRUCTURES AND IMPROVEMENTS		2,378	2,379	2,379	2,379	2,433	2,433	2,433	2,433	2,436	2,440	2,440	2,442	29,004
17	3911	OFFICE FURNITURE		82	82	82	82	82	82	82	82	82	82	82	82	985
18	3912	OFFICE MACHINES		481	481	481	481	481	477	485	485	485	494	428	428	5,687
19	3913	E D P EQUIPMENT		2,367	2,367	2,367	2,794	2,798	3,480	3,674	3,572	3,582	3,599	3,590	3,485	37,675
20	391305	COMPUTER SOFTWARE		8,259	8,259	8,263	8,430	8,430	8,435	8,445	8,445	8,477	8,477	8,477	8,477	100,872
21	3921	TRANSP EQUIP-CARS		428	428	428	428	428	428	428	428	428	428	428	428	5,132
22	3922	TRANS-LIGHT TRUCK, VAN		460	460	460	460	460	460	460	460	460	460	460	460	5,521
23	397	COMMUNICATION EQUIPMENT		410	410	410	410	410	410	410	410	410	410	410	410	4,925
24	398	MISCELLANEOUS EQUIPMENT		18	18	18	18	18	18	26	26	26	26	26	26	269
25	399	TANGIBLE PROPERTY		914	207	207	207	207	207	207	207	207	207	207	207	3,188
26		TOTAL		15,798	15,091	15,095	15,689	15,746	16,431	16,650	16,548	16,593	16,623	16,548	16,445	193,257
27																

Line	(1) Acct 1180	(2) DESCRIPTION	(3) 12 MO TOTAL	(4) ALLOOCATE TO UTILITY ALLOC. %	(5) 13-MO AVG	(6) NON-UTILITY ALLOC. %	(7) 13-MO AVG	(8) ALLOCATION METHOD (G-6, Page 4)
31	390	STRUCTURES AND IMPROVEMENTS	53,711	54%	29,004	46%	24,707	Consolidated Plant Less EDP & Software
32	3911	OFFICE FURNITURE	1,824	54%	985	46%	839	Consolidated Plant Less EDP & Software
33	3912	OFFICE MACHINES	10,532	54%	5,687	46%	4,845	Consolidated Plant Less EDP & Software
34	3913	E D P EQUIPMENT	72,451	52%	37,675	48%	34,776	Consolidated EDP & Software
35	391305	COMPUTER SOFTWARE	193,984	52%	100,872	48%	93,112	Consolidated EDP & Software
36	3921	TRANSP EQUIP-CARS	9,504	54%	5,132	46%	4,372	Consolidated Plant Less EDP & Software
37	3922	TRANS-LIGHT TRUCK, VAN	10,224	54%	5,521	46%	4,703	Consolidated Plant Less EDP & Software
38	397	COMMUNICATION EQUIPMENT	9,120	54%	4,925	46%	4,195	Consolidated Plant Less EDP & Software
39	398	MISCELLANEOUS EQUIPMENT	498	54%	269	46%	229	Consolidated Plant Less EDP & Software
40	399	TANGIBLE PROPERTY	5,904	54%	3,188	46%	2,716	Consolidated Plant Less EDP & Software
41		TOTAL	367,752		193,257		174,495	
		TOTAL PER BOOKS			193,775			
		COMMISSION ADJUSTMENT			(517)			

SUPPORTING SCHEDULES: B-5

RECAP SCHEDULES: C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A RECONCILIATION BETWEEN THE TOTAL OPERATING INCOME TAX PROVISION FOR THE HISTORIC BASE YEAR PERIOD AND THE CURRENTLY PAYABLE INCOME TAXES ON OPERATING INCOME FOR THE HISTORIC BASE YEAR.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	REFERENCE	DESCRIPTION	2007 PER BOOKS	ADJUSTMENTS	2007 ADJUSTED MFR BOOKS
1.	C-21	CURRENT INCOME TAX EXPENSE	1,279,509	187,482	1,466,991
2.					
3.	C-24	DEFERRED INCOME TAX EXPENSE	(494,988)	0	(494,988)
4.					
5.	B-17	ITC AMORTIZATION	(39,372)	0	(39,372)
6.					
7.			----------	----------	----------
8.		TOTAL INCOME TAX EXPENSE	745,149	187,482	932,631
9.			=========	=============	=============
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					
20.					
21.					
22.					

SUPPORTING SCHEDULES: B-17, C-21, C-24

RECAP SCHEDULES: C-1

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE CALCULATION OF STATE AND FEDERAL INCOME TAXES FOR THE HISTORIC BASE YEAR. PROVIDE DETAIL ON ADJUSTMENTS TO INCOME TAXES AND INVESTMENT TAX CREDITS.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	DESCRIPTION		TOTAL UTILITY
1	Utility Taxable Operating Income		4,647,326
2	Less: Interest Charges	Per Book (Calc interest should be 2,300,395)	2,403,532
3			
4	Other Deductions/(Additions)		
5	Depreciation for Tax Purposes		3,564,000
6	Ordinary Loss on ACRS Property		316,800
7	AEP Deprecitaion for Tax Purposes		397,288
8	Amortization of Intangibles		227,545
9	Cost of Removal - ADR Property		13,500
10	Depreciation Expense		(4,170,141)
11	Outside Audit Fees		(14,706)
12	Conservation Program Costs		(117,912)
13	Under/Over Recoveries - Unbundling Costs		
14	Self-Insurance Reserve		(89,905)
15	Taxable Contributions		(973,789)
16	Rate refund		695,075
17	Pension Costs		(921,041)
18	Rate Case Expense		140,312
19	Vacation Pay		(38,229)
20	Uncollectibles		61,936
21	Nondeductible Meals		(8,585)
22	Nondeductible ESPP Compensation Expense		(24,525)
23	Loss on Reacquired Debt		(10,421)
24	Natural Gas Odorizer		(11,089)
25	Gas Unbundling		
26	Environmental Costs		(494,443)
27			
28	Misc. Deferral (Dec. Proc. Int'l. & Monster.com)		
29	Refurbish Project		
30	General Liability		(20,832)
31	Storm Reserve		(896,100)
32	Def. Gain - Delray & Deland		40,653
33	Capitalizes Interest		(257,627)
34	Bare Steel Replacement Program		(566,308)
35	Total Deductions		(3,158,544)
36			
37	Taxable Income		5,402,338

SUPPORTING SCHEDULES: B-17, C-22, C-23 | RECAP SCHEDULES: C-1, C-20

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE CALCULATION OF STATE AND FEDERAL INCOME TAXES FOR THE HISTORIC BASE YEAR. PROVIDE DETAIL ON ADJUSTMENTS TO INCOME TAXES AND INVESTMENT TAX CREDITS.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	DESCRIPTION		TOTAL UTILITY
1.	Taxable Income		5,402,338
2.	Adjustments to State Taxable Income		1,710
3.			
4.	State Taxable Income		5,400,628
5.	State Income Tax Rate	X	5.50%
6.			
7.	State Income Tax Currently Payable		297,035
8.	Rounding		23
9.	State Adjustments		(272,621)
10.	State Income Tax Deferred		(79,930)
11.			
12.	State Income Taxes		(55,493)
13.			
14.	Adjustments to Federal Taxable Income		297,058
15.			
16.	Federal Taxable Income (Line 1 less Line 14)		5,105,280
17.	Federal Income Tax Rate	X	34.00%
18.			
19.	Federal Income Tax Currently Payable		1,735,795
20.	Rounding		5
21.	Federal Adjustments		(293,246)
22.	Federal Income Tax Deferred		(415,058)
23.			
24.	Federal Income Taxes		1,027,496

SUPPORTING SCHEDULES: B-17, C-22, C-23

RECAP SCHEDULES: C-1, C-20

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE CALCULATION OF STATE AND FEDERAL INCOME TAXES FOR THE HISTORIC BASE YEAR. PROVIDE DETAIL ON ADJUSTMENTS TO INCOME TAXES AND INVESTMENT TAX CREDITS.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	DESCRIPTION	TOTAL UTILITY
1.	Line 2, Page 2 - Adjustments to State Taxable Income	
2.		
3.	State Exemption	1,710
4.		
5.	Line 9, Page 2 - Adjustments to State Taxable Income	
6.		
7.	To remove State prior period tax adjustment, interest sync., and income tax effect on other adjustments.	272,621
8.		
9.		
10.		
11.	Total	274,331
12.		
13.		
14.	Line 14, Page 2 - Adjustments to Federal Taxable Income	
15.		
16.	State Income Tax	297,058
17.		
18.	Line 21, Page 2 - Adjustments to Federal Taxable Income	
19.		
20.	To remove Federal tax adjustment, interest sync., and income tax effect on other adjustments.	293,246
21.		
22.		
23.		
24.	Total	590,304

SUPPORTING SCHEDULES: B-17, C-22, C-23

RECAP SCHEDULES: C-1, C-20

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE AMOUNT OF INTEREST EXPENSE USED TO CALCULATE NET OPERATING INCOME TAXES ON SCHEDULE NO. C-21. EXPLAIN ANY ADJUSTMENTS TO INTEREST EXPENSE IN DETAIL GIVING AMOUNT OF CHANGE AND REASON FOR CHANGE. IF THE BASIS FOR ALLOCATING INTEREST USED IN TAX CALCULATION DIFFERS FROM THE BASIS USED IN ALLOCATING CURRENT INCOME TAXES PAYABLE, THE DIFFERING BASIS SHOULD BE CLEARLY IDENTIFIED.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: CAMFIELD, COX

INTEREST IN TAX EXPENSE CALCULATION

LINE NUMBER	DESCRIPTION		2007 13-MO AVERAGE TOTAL COMPANY	ALLOCATED TO GAS	2007 13-MO AVERAGE CONSOLIDATED GAS	2007 COST RATE (%)	2007 INTEREST EXPENSE CONSOLIDATED GAS
1	Long Term Debt		50,535,952	45.8%	23,161,901	8.01%	1,854,224
2	Short-Term Debt		4,500,154	45.8%	2,062,534	4.15%	85,574
3	Preferred Stock		600,000	45.8%	274,995	4.75%	
4	Common Equity		47,816,182	45.8%	21,915,362	11.25%	
5	Customer Deposits	*	5,627,676	100%	5,627,676	6.09%	342,848
6	Deferred Taxes	*	6,286,004	100%	6,286,004	0.00%	
7	ITC at Zero Cost	*	-	100%	-	0.00%	
8	ITC at Overall Cost	*	190,499	100%	190,499	9.32%	17,749
	TOTAL CAPITALIZATION		115,556,468		59,518,973		2,300,395
	CONVENTIONAL CAPITALIZATION (1)-(4)		103,452,288				
	GAS RATE BASE		59,518,973				
	GAS-SPECIFIC CAPITAL ITEMS (5)-(8)		12,104,180				
	GAS RATE BASE LESS GAS-SPECIFIC ITEMS		47,414,793				
	CAPITALIZATION ALLOCATED TO GAS		45.8%				

* GAS SPECIFIC CAPITAL ITEMS

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-20

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE DESCRIPTION AND AMOUNT OF ALL BOOK/TAX DIFFERENCES ACCOUNTED FOR AS PERMANENT DIFFERENCES. THIS WOULD INCLUDE ANY ITEMS ACCOUNTED FOR ON A FLOW THROUGH BASIS.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	DESCRIPTION	TOTAL UTILITY
1	OPERATING INCOME BEFORE TAXES	4,647,326
2	LESS: INTEREST	2,403,532
3		
4	BOOK INCOME	2,243,794
5		
6	EXPECTED TAX PROVISION (LINE 4 X 37.63%)	844,340
7		
8	ACTUAL TAX PROVISION	784,521
9		
10	BOOK/TAX DIFFERENCES	59,819
11		==================
12		
13	BOOK TAX DIFFERENCES:	
14		
15	NONDEDUCTIBLE MEAL ALLOWANCE (8585 X 37.63%)	(3,231)
16		
17	STATE EXEMPTION (1710 X 5.5%)	94
18		
19	FEDERAL TAX EFFECT ON STATE EXEMPTION (96 X 34%)	32
20		
21	Nondeductible ESPP Compensation (24,525 x 37.63%)	(9,229)
22		
23	Prior Period Adjustments	59,819
24		
25	Rounding	12,334
26		
27	BOOK/TAX DIFFERENCE	59,819
		==================

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE CALCULATION OF TOTAL DEFERRED INCOME TAXES FOR THE HISTORIC BASE YEAR. PROVIDE DETAILS ON ITEMS RESULTING IN TAX DEFERRALS OTHER THAN ACCELERATED DEPRECIATION.

TYPE OF DATA SHOWN:

HISTORIC YEAR ENDED: 12/31/07

WITNESS: MARTIN

LINE NO.	DESCRIPTION		FEDERAL @ 32.13%	STATE @ 5.5%
1.	PROPERTY RELATED ITEMS:			
2.				
3.	EXCESS TAX DEPRECIATION	(805,243)		
4.	TAXABLE CONTRIBUTIONS	(973,789)		
5.	ADR COST OF REMOVAL	13,500		
6.	LOSS ON ACRS RETIREMENTS	316,800		
7.				
8.	NET PROPERTY RELATED ITEMS	(1,448,732)	(465,478)	(79,680)
9.				
10.	FULLY NORMALIZED TIMING DIFFERENCES:			
11.	OUTSIDE AUDIT FEES	(14,706)	(4,725)	(809)
12.	CONSERVATION PROGRAM COSTS	(117,912)	(37,885)	(6,485)
13.	UNDER/OVER RECOVERIES-UNBUNDLING COSTS	0	0	0
14.	SELF INSURANCE RESERVE	(89,905)	(28,886)	(4,945)
15.	PENSION COSTS	(921,041)	(295,930)	(50,657)
16.	RATE CASE EXPENSE	835,387	268,410	45,946
17.	VACATION PAY	(38,229)	(12,283)	(2,103)
18.	UNCOLLECTIBLES	61,936	19,900	3,406
19.	LOSS ON REACQUIRED DEBT	(10,421)	(3,348)	(573)
20.	NATURAL GAS ODORIZER	(11,089)	(3,563)	(610)
21.	GAS UNBUNDLING		0	0
22.	ENVIRONMENTAL COSTS	(494,443)	(158,865)	(27,194)
23.	ENVIRONMENTAL DEPRECIATION		0	0
24.	MISC. DEFERRAL (Dec. Proc. Int'l. & Monster.com)		0	0
25.	REFURBISH PROJECT	(20,832)	(6,693)	(1,146)
26.	GENERAL LIABILITY	(896,100)	(287,917)	(49,286)
27.	DEF. GAIN - DELRAY & DELAND		0	0
28.	STORM RESERVE	40,653	13,062	2,236
29.				
30.	TOTAL NORMALIZED ITEMS	(1,676,702)	(538,723)	(92,220)
31.				
32.	ADJUSTMENTS		589,143	91,970
33.				
34.	TOTAL DEFERRED TAXES		(415,058)	(79,930)

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-20

SCHEDULE: C-25 DEFERRED TAX ADJUSTMENT PAGE 1 FOF 1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE THE INFORMATION REQUIRED TO ADJUST THE DEFERRED TAX BALANCES FOR CHANGES IN THE STATE AND FEDERAL STATUTORY INCOME TAX RATES. SHOW SUPPORTING CALCULATIONS IN DETAIL BY VINTAGE YEARS. PROTECTED DEFERRED TAX BALANCES ARE NOT SUBJECT TO THIS ADJUSTMENTS.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
PROJECTED YEAR ENDED: 12/31/2008
PROJECTED TEST YEAR ENDED: 12/31/2009
WITNESS: MARTIN

Line No.	Vintage Year	(1) Book Deprec.	(2) Book Depr. Non-Base *	(3) Net Book (1)-(2)	(4) Tax Deprec.	(5) Excess (4)-(3)	(6) Non-Base Items	(7) Book Depr. Non-Base *	(8) Net Non-Base (6)-(7)	(9) Total Excess (5)+(8)	(10) Target Deferred Taxes (9)xCurr. Rate	(11) Fed & State Cumulative	(12) Excess (10)-(11)
1.	Pre 1971	4,389,247	-	4,389,247	5,549,635	1,160,388		-	-	1,160,388	436,654	(824,699)	1,261,353
2.	1971	214,533	1,680	212,853	264,769	51,916	5,036	1,680	3,356	55,272	20,799	191,428	(170,629)
3.	1972	297,343	1,687	295,656	368,894	73,238	5,058	1,687	3,371	76,609	28,828	17,392	11,436
4.	1973	352,770	13,401	339,369	403,476	64,107	40,182	13,401	26,781	90,888	34,201	284,643	(250,442)
5.	1974	411,914	13,659	398,255	477,084	78,829	40,956	13,659	27,297	106,126	39,935	191,494	(151,559)
6.	1975	606,421	2,350	604,071	755,617	151,546	7,045	2,350	4,695	156,241	58,793	201,470	(142,677)
7.	1976	297,057	1,653	295,404	368,635	73,231	4,957	1,653	3,304	76,535	28,800	94,746	(65,946)
8.	1977	595,797	3,924	591,873	737,535	145,662	11,766	3,924	7,842	153,504	57,764	150,475	(92,711)
9.	1978	281,122	3,671	277,451	342,544	65,093	11,007	3,671	7,336	72,429	27,255	150,036	(122,781)
10.	1979	951,691	4,100	947,591	1,184,596	237,005	12,293	4,100	8,193	245,198	92,268	77,287	14,981
11.	1980	616,021	5,233	610,788	759,044	148,256	15,691	5,233	10,458	158,714	59,724	99,054	(39,330)
12.	1981	784,161	-	784,161	986,196	202,035		-	-	202,035	76,026	193,071	(117,045)
13.	1982	1,286,995	-	1,286,995	1,618,582	331,587		-	-	331,587	124,776	224,435	(99,659)
14.	1983	1,016,617	-	1,016,617	1,278,543	261,926		-	-	261,926	98,563	126,786	(28,223)
15.	1984	802,458	-	802,458	1,009,207	206,749		-	-	206,749	77,800	118,040	(40,240)
16.	1985	749,651	-	749,651	942,795	193,144		-	-	193,144	72,680	157,346	(84,666)
17.	1986	1,391,926	7	1,391,919	1,750,528	358,609	20	7	13	358,622	134,949	318,123	(183,174)
18.	1987	1,516,845	(242)	1,517,087	1,910,836	393,749	(726)	(242)	(484)	393,265	147,986	310,673	(162,687)
19.	1988	1,383,592	-	1,383,592	1,754,310	370,718		-	-	370,718	139,501	180,858	(41,357)
20.	1989	1,651,200	(532)	1,651,732	2,093,690	441,958	(1,595)	(532)	(1,063)	440,895	165,909	334,282	(168,373)
21.	1990	1,171,015	(321)	1,171,336	1,492,074	320,738	(963)	(321)	(642)	320,096	120,452	230,584	(110,132)
22.	1991	1,188,076	(382)	1,188,458	1,589,447	400,989	(1,146)	(382)	(764)	400,225	150,605	126,173	24,432
23.	1992	3,112,723	(876)	3,113,599	3,950,175	836,576	(2,628)	(876)	(1,752)	834,824	314,144	623,449	(309,305)
25.	1993	2,129,246	(106)	2,129,352	2,700,561	571,209	(318)	(106)	(212)	570,997	214,866	410,046	(195,180)
26.	1994	1,890,594	(4,734)	1,895,328	2,411,754	516,426	(14,195)	(4,734)	(9,461)	506,965	190,771	276,491	(85,720)
27.	1995	2,154,537	(6,367)	2,160,904	2,768,132	607,228	(19,091)	(6,367)	(12,724)	594,504	223,712	319,556	(95,844)
28.	1996	2,353,031	(1,964)	2,354,995	3,051,299	696,304	(5,888)	(1,964)	(3,924)	692,380	260,543	351,541	(90,998)
29.	1997	2,200,106	(1,949)	2,202,055	2,947,869	745,814	(5,844)	(1,949)	(3,895)	741,919	279,184	287,409	(8,225)
30.	1998	2,892,457	(69,577)	2,962,034	3,979,617	1,017,583	(208,628)	(69,577)	(139,051)	878,532	330,592	211,894	118,698
31.	1999	2,454,058	(343,884)	2,797,942	4,333,003	1,535,061	(1,031,135)	(343,884)	(687,251)	847,810	319,031	77,764	241,267
32.	2000	3,259,902	(246,709)	3,506,611	5,167,326	1,660,715	(739,756)	(246,709)	(493,047)	1,167,668	439,393	451,610	(12,217)
33.	2001	6,677,648	(340,149)	7,017,797	9,715,498	2,697,701	(1,019,936)	(340,149)	(679,787)	2,017,914	759,341	387,599	371,742
34.	2002	8,915,308	(414,996)	9,330,304	12,938,731	3,608,427	(1,244,365)	(414,996)	(829,369)	2,779,058	1,045,760	1,230,648	(184,888)
35.	2003	3,617,459	349,032	3,268,427	5,118,462	1,850,035	1,046,572	349,032	697,540	2,547,575	958,652	889,447	69,205
36.	2004	4,013,499	666,624	3,346,875	3,460,071	113,196	1,998,872	666,624	1,332,248	1,445,444	543,921	1,277,809	(733,888)
37.	2005	4,859,201	500,066	4,359,135	4,758,531	399,396	1,499,448	500,066	999,382	1,398,778	526,360	803,628	(277,268)
38.	2006	6,359,772	(288,725)	6,648,497	10,010,019	3,361,522	(865,743)	(288,725)	(577,018)	2,784,504	1,047,809	(551,935)	1,599,744
TOTALS		78,845,993	(154,429)	79,000,422	104,949,085	25,948,664	(463,054)	(154,429)	(308,626)	25,640,038	9,648,346	10,000,653	(352,307)

* Book Reserve/ Book Basis = 25,303,466.25 / 75,883,311.07 = 33.35%

SUPPORTING SCHEDULES: B-18 RECAP SCHEDULES:

SCHEDULE C-26	PARENT(S) DEBT INFORMATION	PAGE 1 OF 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	EXPLANATION: PROVIDE INFORMATION REQUIRED IN ORDER TO ADJUST INCOME TAX EXPENSE BY REASON OF INTEREST EXPENSE OF PARENT(S) THAT MAY BE INVESTED IN THE EQUITY OF THE APPLICANT. IF YEAR-END RATE BASE IS USED, PROVIDE ON BOTH A YEAR-END AND 13-MONTH AVERAGE BASIS. AMOUNTS SHOULD BE PARENT ONLY	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/2007 WITNESS: CAMFIELD, COX

LINE NO.		AMOUNT	PERCENT OF CAPITAL	COST RATE	WEIGHTED COST	WEIGHTED COST OF DEBT
1	LONG TERM DEBT					
2	SHORT TERM DEBT		NOT APPLICABLE**			
3	PREFERRED STOCK					
4	COMMON EQUITY					
5	RETAINED EARNINGS					
6	DEFERRED INCOME TAX					
7	INVESTMENT TAX CREDITS					
8	OTHER					
9	TOTAL					
10	WEIGHTED COST OF PARENT DEBT x 37.63% (OR APPLICABLE CONSOLIDATED TAX RATE) x EQUITY OF SUBSIDIARY					

** NOTE: CONSOLIDATED GAS DIVISION IS A DIVISION OF FLORIDA PUBLIC UTILITIES COMPANY AND AS SUCH SHARES THE "COMMON" SOURCES OF CAPITAL WITH OTHER OPERATIONS. THE "COMMON" SOURCES OF CAPITAL ARE COMMON AND PREFERRED EQUITY, AND LONG AND SHORT TERM DEBT (SCHEDULE D-1). THE BASIS OF SHARING IS THE APPLICABLE RATE BASE (SCHEDULE B-2). THE ALLOCATION OF "COMMON" CAPITAL IS SHOWN ON SCHEDULE C-22.

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-20

SCHEDULE C-27	INCOME TAX RETURNS	PAGE 1 OF 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	EXPLANATION: PROVIDE A COPY OF THE MOST RECENTLY FILED FEDERAL INCOME TAX RETURN, STATE INCOME TAX RETURN, AND MOST RECENT FINAL IRS REVENUE AGENT'S REPORT FOR THE APPLICANT OR CONSOLIDATED ENTITY (WHICHEVER TYPE IS FILED). A STATEMENT OF WHEN AND WHERE THE RETURNS AND REPORTS ARE AVAILABLE FOR REVIEW MAY BE PROVIDED IN LIEU OF PROVIDING THE RETURNS AND REPORTS.	TYPE OF DATA SHOWN: HISTORIC YEAR ENDED: 12/31/2007 WITNESS: MARTIN

ALL THE ABOVE RETURNS AND REPORTS ARE AVAILABLE UPON REASONABLE NOTICE AND DURING NORMAL BUSINESS HOURS AT THE COMPANY'S GENERAL OFFICE AT 401 SOUTH DIXIE HWY., WEST PALM BEACH, FLORIDA.

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE ANSWERS TO THE FOLLOWING QUESTIONS

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

HISTORIC YEAR ENDED: 12/31/2007

WITNESS: MARTIN

LINE NO.		
1.	FOR PROFIT AND LOSS PURPOSES, WHICH IRC SECTION 1552 METHOD	SECTION 1.1552-1(A)
2.	IS USED FOR TAX ALLOCATION?	
3.		
4.	WHAT TAX YEARS ARE OPEN WITH THE IRS?	2005 FORWARD
5.		
6.	IS THE TREATMENT OF CUSTOMER DEPOSITS AT ISSUE WITH THE IRS?	NO
7.		
8.	IS THE TREATMENT OF CIAC AT ISSUE WITH THE IRS?	NO
9.		
10.	IS THE TREATMENT OF UNBILLED REVENUE AT ISSUE WITH THE IRS?	NO
11.		
12.	FOR THE LAST 5 TAX YEARS, WHAT DOLLARS WERE PAID OR RECEIVED	
13.	FROM THE PARENT FOR FEDERAL INCOME TAXES?	NOT APPLICABLE
14.		
15.	HOW WERE THE AMOUNTS IN 6 TREATED?	NOT APPLICABLE
16.		
17.	FOR THE LAST 5 TAX YEARS, WHAT WAS THE DOLLAR AMOUNT	
18.	OF INTEREST DEDUCTED ON THE PARENT-ONLY TAX RETURN?	NOT APPLICABLE
19.		
20.	COMPLETE THE FOLLOWING CHART FOR THE LAST 5 YEARS WITH RESPECT TO TAXABLE INCOME.	
22.		

LINE NO.											
23.		INCOME/(LOSS)									
24.											
25.		BOOK BASIS					TAX BASIS				
26.		YEAR					YEAR				
27.											
28.		2003	2004	2005	2006	2007	2003	2004	2005	2006	2007
29.											
30.	PARENT ONLY	NOT APPLICABLE					NOT APPLICABLE				
31.											
32.	APPLICANT ONLY	NOT APPLICABLE					NOT APPLICABLE				
33.											
34.	TOTAL GROUP (1)	12,423,000*	3,594,000	4,248,000	4,169,000	3,301,000 *	1,453,845	(380,767)	4,978,347	10,720,047	6,181,128
36.											
37.	TOTAL GROUP EXCLUDING										
38.	PARENT & APPLICANT	NOT APPLICABLE					NOT APPLICABLE				

(1) FPUC CONSOLIDATED INCLUDES WHOLLY OWNED SUBSIDIARY, FLO-GAS CORPORATION. THE APPLICANT, CONSOLIDATED GAS DIVISIONS - ARE OPERATING DIVISIONS OF FPUC.
* INCLUDED INCOME FROM DISCONTINUED OPERATIONS - SALE OF WATER ASSETS

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SUMMARY OF THE SPECIFIC TAX EFFECT (IN DOLLARS) OF FILING A CONSOLIDATED RETURN FOR THE HISTORIC BASE YEAR. IDENTIFY THE NATURE AND AMOUNTS OF BENEFITS TO THE COMPANY AND THE RATEPAYERS. PROVIDE A COPY OF ANY EXISTING TAX-SHARING AGREEMENTS WITH AFFILIATED COMPANY.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: MARTIN

TOTAL TAXABLE INCOME FOR THE HISTORIC BASE YEAR 2003 WILL BE INCLUDED IN THE CONSOLIDATED INCOME TAX RETURN FOR FPUC, PARENT COMPANY OF FLO-GAS CORPORATION. TAX IS ALLOCATED TO THE COMPANY BASED ON COMPUTATION AS IF SEPARATE RETURNS WERE FILED. THERE IS NO INTERCOMPANY ELIMINATION BETWEEN THE COMPANY AND IT'S SUBSIDIARY WHICH AFFECTS TAXABLE INCOME.

THERE IS NO SPECIFIC BENEFIT TO THE COMPANY AND THE RATEPAYERS RESULTING FROM FILING A CONSOLIDATED RETURN.

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF TAXES OTHER THAN INCOME TAXES FOR THE HISTORIC BASE YEAR AND THE PRIOR YEAR. FOR EACH TAX, INDICATE THE AMOUNT CHARGED TO OPERATING EXPENSES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
HISTORICAL PRIOR YEAR: 12/31/06

WITNESS: COX

			YEAR ENDED 2006			YEAR ENDED 2007		
LINE NO.	ACCOUNT 4080 SUB ACCOUNT	TYPE OF TAX	BASIS	GAS UTILITY	CHARGED TO OPERATING EXP	BASIS	GAS UTILITY	CHARGED TO OPERATING EXP
1.	5	FEDERAL UNEMPLYOMENT	PAYROLL	14,366	2,843	PAYROLL	13,955	7,125
2.								
3.	6	STATE UNEMPLOYMENT	PAYROLL	22,696	970	PAYROLL	6,803	2,482
4.								
5.	7	FICA	PAYROLL	748,077	565,920	PAYROLL	763,043	557,003
6.								
7.	2	STATE GROSS RECEIPTS	REVENUE	2,047,917	2,047,917	REVENUE	2,105,766	2,105,766
8.								
9.	11	FRANCHISE FEE	VARIOUS RATES	1,626,445	1,626,445	VARIOUS RATES	1,533,487	1,533,487
10.								
11.	4	EMERGENCY EXCISE TAX	ACRS DEPR	(10,095)	(10,095)	ACRS DEPR	(1,016)	(1,016)
12.								
13.	8	MISCELLANEOUS TAX	FLAT	1,559	1,559	FLAT	6,331	6,331
14.								
15.	1	PROPERTY	PROPERTY	1,120,147	1,120,147	PROPERTY	1,187,078	1,187,078
16.								
17.	3	UTILITY ASSESSMENT FEE	REVENUE	370,340	370,340	REVENUE	318,499	318,499
18.		**TOTAL TAXES OTHER THAN INCOME**		5,941,451	5,726,046		5,933,947	5,716,755

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION:COMPLETE THE FOLLOWING INFORMATION REGARDING THE USE OF OUTSIDE PROFESSIONAL SERVICES DURING THE HISTORIC BASE YEAR PERIOD.SPECIFY BY CONTRACT AREAS SUCH AS ACCOUNTING, LEGAL, FINANCIAL OR ENGINEERING.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

LINE NO.	TYPE OF SERVICE PERFORMED	NAME OF CONTRACTOR	PROJECT	CONTRACT TYPE (CHECK ONE) ONE-TIME	CONTINUING	PERIOD OF CONTRACT BEGIN	END	ACCOUNT CHARGED (#)	2007 INVOICE COST	NG Alloc %	CONSOLIDATED NATURAL GAS COST	ACCOUNT
1	1) ACCOUNTING	BDO Seidmann, LLP	Independent auditors		X	1/1/2007	12/31/2007	100.2420.3	250,000	0.51	127,500	923.3
2		Ana Blanchard	Tax		X			100.2420.3	37,590	0.51	19,171	923.3
3		Crowe Chezik	Internal Auditing		X			100.2420.3	112,494	0.51	57,372	923.3
4		RSM McGladrey	Impairment testing		X			100.2420.3	16,750	0.51	8,543	923.3
5												
6												
7	2) LEGAL	Akerman, Senterfitt & Eidson	Environmental MGP Plant Sites		X			100.2530.31	110,173	1.00	110,173	2530.31
8		Akerman, Senterfitt & Eidson	Liability Litigation		X			100.2280.201	479,269	0.51	244,427	923.2
9		Akerman, Senterfitt & Eidson	Land Purchase/Escrow Lake Park	X				100.1860.1	83,963	1.00	83,963	1070
10		Akerman, Senterfitt & Eidson	Sale Regulator Sta. Prop. W/easement reserves	X				100.1860.1	3,032	1.00	3,032	880.2
11		Akerman, Senterfitt & Eidson	Employee Litigation NE Division	X				995.4010.9232	18,891	0.00	-	
12		Akerman, Senterfitt & Eidson	Bond Requirements		X			100.1849.9232	4,387	0.51	2,237	923.2
13		Akerman, Senterfitt & Eidson	Miscellaneous (6 Items)		X			Various	5,517		1,813	Various
14		Akerman, Senterfitt & Eidson										
15												
16		Jackson Lewis LLP	HR Legal Fees - Misc.		X			100.2420.31	17,083	0.51	8,713	923.2
17		Jackson Lewis LLP	Retainer		X			100.2420.31	9,900	0.51	5,049	923.2
18		Jackson Lewis LLP	Training for Supervisors		X			100.1849.9261	5,750	0.52	2,990	926.1
19												
20		Bryan Cave	Legal Retainer		X			100.2420.31	18,000	0.51	9,180	923.2
21		Bryan Cave	Corporate securities & SEC Review		X			100.2420.31	30,023	0.51	15,312	923.2
22		Bryan Cave	Harassment Training for Supervisors		X			100.1849.9215	3,200	0.46	1,472	921.5
23												
24		Messer, Caparello & Self	Electric Fuel Surcharge	X				114,115.4010.557	14,424	0.00	-	
25		Messer, Caparello & Self	Electric Fuel RFP's	X				114,115.4010.928	7,847	0.00	-	
26		Messer, Caparello & Self	Electric Rate Case	X				100.1860.1	58,889	0.00	-	
27		Messer, Caparello & Self	General Regulatory Business		X			100.1840.928	14,790	0.62	9,170	928
28		Messer, Caparello & Self	Electric Storm Surcharge Petition	X				114,115.4010.928	14,007	0.00	-	
29		Messer, Caparello & Self	N. Gas Over Earnings & Generator Tariff	X				121,123.4010.928	3,300	1.00	3,300	928
30		Messer, Caparello & Self	Electric Conservation		X			114,115.4010.910	320	0.00	-	
31		Messer, Caparello & Self	N. Gas Conservation		X			121,123.4010.928	320	1.00	320	928
32		Messer, Caparello & Self	Misc. N. Gas (2 items)		X			121.4010.870/928	425	1.00	425	870/928
33												
34	3) FINANCIAL	AON	Actuary Services		X			100.2420.3	66,811	0.00	34,074	923.3
35												
36												
37	4) ENGINEERING	Shelton, Charles	Safety Coordinator Elect. Divisions		X			114,115.4010.9251	46,626	0.00	-	
38		Geosyntec Consultants	Environmental Work Land Purchase - L.Pk.	X				100.1860.1	15,396	1.00	15,396	1070
39		Anderson Moore Constr.	Site Plan - Land Purchase - L.Pk.	X				100.1860.1	32,550	1.00	32,550	1070
40		ENSR Corporation	Environmental Study - MGP Plant sites		X			100.2530.31	17,852	1.00	17,852	2530.31
41												
42	5) OTHER (SPECIFY)											
43		Darryl Troy	Consultant - Electric Rate Case	X				100.1860.1	19,500	0.00	-	
44		Darryl Troy	Propane Inventory		X			99X.923.1	7,231	0.00	-	
45		Darryl Troy	Misc. Items (2)	X				121.1430.1	453	0.00	-	
46		Laurits R. Christiansen, Assoc.	Electric Rate Case	X				100.1860.1	165,000	0.00	-	
47		Laurits R. Christiansen, Assoc.	Electric Fuel Issues	X				114&115.4010.557	72,332	0.00	-	
48		Callaway & Price	Appraisal of Regulator Sta. Property	X				100.1860.1	3,200	1.00	3,200	880.2
49		Callaway & Price	Appraisal of WPB MGP Plant Site		X			100.2530.31	5,000	1.00	5,000	2530.31
50		The Retec Group, Inc.	Environmental MGP Plant Sites		X			100.2530.31	23,433	1.00	23,433	2530.31
51		McGriff, Seibels & Williams	Liability Insurance Broker		X			100.1650.2	42,500	0.42	17,850	924/925.2
								TOTAL CONTRACTUAL EXPENSES	1,838,228		863,517	

SUPPORTING SCHEDULES: RECAP SCHEDULES:

SCHEDULE C-32 TRANSACTIONS WITH AFFILIATED COMPANIES

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE DETAILING TRANSACTIONS WITH AFFILIATED COMPANIES AND RELATED PARTIES FOR THE HISTORIC BASE YEAR INCLUDING INTERCOMPANY CHARGES, LICENSES, CONTRACTS, AND FEES.IF THE DATA REQUESTED IS ALREADY ON FILE WITH THE COMMISSION,(AS REQUIRED BY RULE 25-7.014) AND IS BASED ON THE SAME PERIOD AS THE HISTORIC YEAR, A STATEMENT TO THAT AFFECT WILL BE SUFFICIENT

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: COX

TRANSACTIONS WITH AFFILIATED COMPANIES FLO-GAS

	NAME OF COMPANY OR RELATED PARTY	RELATION TO UTILITY	TYPE OF SERVICE PROVIDED OR RECEIVED	EFFECTIVE CONTRACT DATE	CHARGE OR (CREDIT) DURING YEAR AMOUNT	ACCOUNT NO.	ALLOCATION METHOD USED TO ALLOCATE CHARGES BETWEEN COMPANIES
1)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Labor		$3,078,701	146	Actual use of personnel and various allocation factors
2)	Flo-Gas Corporation	Wholly-Owned Subsidiary	InterCompany Interest		887,408	146	Actual based on InterCompany Receivables
3)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Merchandise, Materials & Supplies		198,399	146	Actual use of materials or merchandise
4)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Cash Receipts & Disbursements		(4,278,399)	146	Actual and/or various allocation basis
5)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Transportation		149,375	146	Actual use of vehicles and various allocation basis
6)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Dividends		2,000,000	146	Actual Amount as Declared
7)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Corporate expenses charged to clearing		819,127	146	Various allocation basis
8)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Insurance		144,411	146	Various allocations
9)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Sale of Assets		(739,735)	146	Sales contracts or agreements
10)	Flo-Gas Corporation	Wholly-Owned Subsidiary	Miscellaneous Items		(459,836)	146	Actual and/or various allocation basis
11)			TOTAL NET AMOUNT		$1,799,451		

SUPPORTING SCHEDULES: RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A COMPARISON OF WAGE AND SALARY INCREASES FOR THE LAST THREE YEARS AND HISTORIC BASE YEAR TO THE CPI.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
HISTORIC BASE YR - 1: 2006
HISTORIC BASE YR - 2: 2005
HISTORIC BASE YR - 3: 2004
WITNESS: LUNDGREN

INCREASE IN WAGES AND SALARY BY GROUP	2004	2005	2006	HISTORIC YEAR 2007
SUPERVISORY	3.00%	3.25%	3.50%	3.50%
UNION	3.00%	3.25%	3.50%	3.50%
OPERATIONS	3.00%	3.25%	3.50%	3.50%
TOTAL INCREASE	3.00%	3.25%	3.50%	3.50%
CHANGE IN CPI FROM PREVIOUS YEAR	2.66%	3.39%	3.23%	2.83%
DIFFERENCE BETWEEN INCREASE IN WAGES AND SALARIES AND CPI	0.34%	-0.14%	0.27%	0.67%

NOTE: THE ABOVE % INCREASES ARE ANNUAL SALARY RANGE INCREASES. THE COMPANY ALSO PERMITTED ADDITIONAL MERIT INCREASES AS FOLLOWS:

SUPERVISORY	3.00% to 6.00%	3.00% to 6.00%	3.00% to 6.00%	1.00% to 2.00%
UNION	0.30% to 7.90%	0.30% to 7.90%	0.30% to 7.90%	0.30% to 7.90%
OPERATIONS	3.00% to 6.00%	3.00% to 6.00%	3.00% to 6.00%	1.00% to 2.00%

TOTAL PAYROLL INCREASE AS FOLLOWS:

SUPERVISORY	6.00% to 9.00%	6.25% to 9.25%	6.50% to 9.50%	4.50% to 5.50%
UNION	3.30% to 10.90%	3.55% TO 11.15%	3.80% TO 11.40%	3.80% TO 11.40%
OPERATIONS	6.00% to 9.00%	6.25% to 9.25%	6.50% to 9.50%	4.50% to 5.50%

SUPPORTING SCHEDULES: C-37

RECAP SCHEDULES:

SCHEDULE C-34 | O & M BENCHMARK COMPARISON BY FUNCTION |

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR THE HISTORIC BASE YEAR FUNCTIONALIZED O & M EXPENSE PLEASE PROVIDE THE BENCHMARK VARIANCES.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
PRIOR RATE CASE BASE YR: 12/31/2003
WITNESS: LUNDGREN

LINE NO.	FUNCTION	COL 1 HISTORIC YEAR TOTAL COMPANY PER BOOKS (MFR C-1) (CURRENT CASE)	COL 2 O & M ADJUSTMENTS (MFR C-2) (CURRENT CASE)	COL 3 ADJUSTED HISTORIC YEAR O & M (MFR C-1) (CURRENT CASE)	COL 4 2003 BASE YEAR ADJUSTED O & M (MFR C-36) (PRIOR CASE)	COL 5 COMPOUND MULTIPLIER (MFR C-37)	COL 6 HISTORIC BASE YEAR BENCHMARK (COL 4 X 5)	COL 7 BENCHMARK VARIANCE (MFR C-38) (COL 6 - 3)
1	OTHER GAS SUPPLY EXPENSE	169,667	0	169,667	151,392	1.2335	186,742	(17,075)
2	DISTRIBUTION	5,380,351	0	5,380,351	4,723,687	1.2335	5,826,668	(446,317)
3	CUSTOMER ACCOUNTS	2,650,393	0	2,650,393	1,947,571	1.2335	2,402,329	248,064
4	SALES EXPENSE	1,747,408	(23,035)	1,724,373	1,653,719	1.2335	2,039,862	(315,489)
5	ADMINISTRATIVE & GENERAL	5,358,644	47,656	5,406,300	3,742,776	1.2335	4,616,714	789,586
6								
7								
8	TOTAL	15,306,463	24,621	15,331,084	12,219,145		15,072,315	258,769

NOTE: FUEL & CONSERVATION HAVE BEEN REMOVED FROM THIS RATE PROCEEDING

SUPPORTING SCHEDULES: C-2, C-5, C-35, C-36, C-37, C-38

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE THE DETAIL OF ADJUSTMENTS MADE TO THE HISTORIC BASE YEAR PER BOOKS O & M EXPENSES BY FUNCTION.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

LINE NO.	FUNCTION	ADJUSTMENT	EXPLANATION
1	OTHER GAS SUPPLY EXPENSE	0	FOR ADJUSTMENTS AND EXPLANATIONS SEE SCHEDULE C-2
2	DISTRIBUTION	0	
3	CUSTOMER ACCOUNTS	0	
4	SALES EXPENSE	(23,035)	
5	ADMINISTRATIVE & GENERAL	47,656	
6	GAS SUPPLY EXPENSE	(32,319,861)	
7	CONSERVATION	(2,292,190)	
8	TOTAL	(34,587,430)	

NOTE: FUEL & CONSERVATION HAVE BEEN REMOVED FROM THIS RATE PROCEEDING

SUPPORTING SCHEDULES: C-2

RECAP SCHEDULES: C-34

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE ADJUSTMENTS TO BASE YEAR (PRIOR CASE) O & M EXPENSES RELATED TO EXPENSES RECOVERABLE THROUGH MECHANISMS OTHER THAN BASE RATES. EXPLAIN ANY ADJUSTMENTS.

TYPE OF DATA SHOWN:
PRIOR RATE CASE BASE YR: 12/31/2003
WITNESS: LUNDGREN

LINE NO.	FUNCTION	BASE YEAR ACTUAL O&M	ADJUSTMENTS FOR NON-BASE RATE EXPENSE RECOVERIES	BASE YEAR ADJUSTED O&M	EXPLANATION
1	OTHER GAS SUPPLY EXPENSE	131,581	19,811	151,392	Ongoing Unbundling Costs (acct. 814) in this rate case Docket 080366-GU is being classified as part of base rates. This adj. is necessary to also reclassify the same account in the 2003 rate case for comparative purposes.
2	DISTRIBUTION	4,723,687	0	4,723,687	
3	CUSTOMER ACCOUNTS	1,947,571	0	1,947,571	
4	SALES EXPENSE	1,653,719	0	1,653,719	
5	ADMINISTRATIVE & GENERAL	3,742,776	0	3,742,776	
6					
7					
8	TOTAL	12,199,334	19,811	12,219,145	

SUPPORTING SCHEDULES: RECAP SCHEDULES: C-34

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FOR EACH YEAR SINCE THE BASE YEAR OF THE COMPANY'S LAST RATE CASE, PROVIDE THE AMOUNTS AND PERCENT INCREASES ASSOCIATED WITH CUSTOMERS AND AVERAGE CPI. SHOW THE CALCULATION FOR EACH COMPOUND MULTIPLIER.

TYPE OF DATA SHOWN:
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

	TOTAL CUSTOMERS			AVERAGE CPI			INFLATION & GROWTH COMPOUND MULTIPLIER
YEAR	AMOUNT	% INCREASE	A COMPOUND MULTIPLIER	AMOUNT	% INCREASE	B COMPOUND MULTIPLIER	(A X B)
2003	47,121		1.0000	184.0		1.0000	1.0000
2004	48,701	3.35%	1.0335	188.9	2.66%	1.0266	1.0611
2005	50,247	3.17%	1.0663	195.3	3.39%	1.0614	1.1318
2006	51,213	1.92%	1.0868	201.6	3.23%	1.0957	1.1908
2007	51,590	0.74%	1.0948	207.3	2.83%	1.1266	1.2335

SUPPORTING SCHEDULES:

RECAP SCHEDULES: C-33, C-34

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF OPERATION AND MAINTENANCE EXPENSE BY FUNCTION FOR THE HISTORIC BASE YEAR, THE BENCHMARK YEAR AND THE VARIANCE. FOR EACH FUNCTIONAL VARIANCE, JUSTIFY THE DIFFERENCE.

TYPE OF DATA SHOWN:
HIS. BASE YR LAST CASE: 12/31/2003
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

FERC ACCOUNTS: 901 - 905 FERC FUNCTIONAL GROUP: CUSTOMER ACCOUNTS

	AMOUNT
TEST YEAR ADJUSTED REQUEST	2,650,393
BENCHMARK	2,402,329
VARIANCE TO JUSTIFY	248,064

LINE NO.	JUSTIFICATION NO.	DESCRIPTION	BASE YEAR (PRIOR CASE) ACTUAL O&M	BENCHMARK	HISTORIC BASE YEAR O&M REQUESTED	BENCHMARK VARIANCE	JUSTIFICATION ON PAGE # *
1	CA - 1	SUBCONTRACTED METER READING (902)	291,213	359,211	528,387	169,176	SEE BELOW
2	CA - 2	UNCOLLECTIBLE ACCOUNTS EXPENSE (904)	188,003	231,902	243,221	11,319	"
3	CA - 3	HIRING OF ADDITIONAL COLLECTOR (903)	45,165	55,711	96,474	40,763	"
4	CA - 4	OUT-OF-PERIOD STATE SALES TAX ADJUSTMENT (905)	(10,892)	(13,435)	0	13,435	"
5	CA - 5	TRANSPORTATION COST (903)	37,609	46,391	64,459	18,068	"

* ATTACH ADDITIONAL PAGES AS NECESSARY TO PROVIDE COMPLETE JUSTIFICATION FOR VARIANCE.

JUSTIFICATION

CA-1 THE COMPANY OUTSOURCED METER READING IN 2006 TO REDUCE OVERALL PAYROLL AND RELATED PAYROLL BENEFITS SUCH AS PENSIONS, 401K, INSURANCE AND PAYROLL TAXES; AND ALSO INCREASING VEHICLE EXPENSES. SOME COMPANY METER READERS WERE RE-ASSIGNED TO EXPANDED COLLECTIONS EFFORT.

CA-2 NET CHARGE-OFFS HAVE EXCEEDED BENCHMARK DUE TO INCREASES IN BASE AND PGA RATES OVER PAST FOUR YEARS, HIRING ADDITIONAL COLLECTORS AND SLOWING ECONOMIC CONDITIONS.

CA-3 AN ADDITIONAL COLLECTOR WAS HIRED IN 2006 TO HELP STABILIZE RISING BAD DEBT WRITE-OFFS DUE TO ECONOMIC CONDITIONS AND LOSS OF COMPANY METER READERS WHICH WERE ASSISTING WITH COLLECTIONS IN PRIOR YEARS.

CA-4 CREDIT FOR OVERPAYMENT OF STATE SALES TAXES IN 2001 & 2002 RECORDED IN 2003. NON-RECURRING CREDIT.

CA-5 INCREASE IN TRANSPORTATION COST - PRIMARILY THE INCREASE IN GASOLINE COSTS OVER FOUR YEARS.

SUPPORTING SCHEDULES: C-34 RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A SCHEDULE OF OPERATION AND MAINTENANCE EXPENSE BY FUNCTION FOR THE HISTORIC BASE YEAR, THE BENCHMARK YEAR AND THE VARIANCE. FOR EACH FUNCTIONAL VARIANCE, JUSTIFY THE DIFFERENCE.

TYPE OF DATA SHOWN:
HIS. BASE YR LAST CASE: 12/31/2003
HISTORIC YEAR ENDED: 12/31/2007
WITNESS: LUNDGREN

FERC ACCOUNTS: 920 - 935 FERC FUNCTIONAL GROUP: ADMINISTRATIVE & GENERAL

	AMOUNT
TEST YEAR ADJUSTED REQUEST	5,406,300
BENCHMARK	4,616,714
VARIANCE TO JUSTIFY	789,586

LINE NO.	JUSTIFICATION NO.	DESCRIPTION	BASE YEAR (PRIOR CASE) ACTUAL O&M	BENCHMARK	HISTORIC BASE YEAR O&M REQUESTED	BENCHMARK VARIANCE	JUSTIFICATION * ON PAGE #
1	AG -1	STORM RECOVERY EXPENSES (924)	0	0	163,543	163,543	SEE BELOW
2	AG -2	COMPANY PENSION PLAN EXPENSE (9261)	272,837	336,544	673,678	337,134	SEE BELOW
3	AG -3	COMPANY 401K MATCHING PLAN (9264)	0	0	36,647	36,647	SEE BELOW
4	AG -4	RATE CASE EXPENSE WRITE-OFF (928)	0	0	88,630	88,630	SEE BELOW
5	AG -5	SELF-INSURANCE - GENERAL LIABILITY	125,400	154,681	488,691	334,010	SEE BELOW

* ATTACH ADDITIONAL PAGES AS NECESSARY TO PROVIDE COMPLETE JUSTIFICATION FOR VARIANCE.

JUSTIFICATION

AG -1 THE COMPANY APPLIED A SURCHARGE TO NATURAL GAS RATES DURING 2007 TO RECOVER PAST DEFERRED STORM COSTS PER COMMISSION ORDER NO. PSC-05-1040-PAA-GU. FULL RECOVERY OF STORM COSTS WERE COMPLETE IN OCTOBER, 2007. THERE WAS NO STORM RECOVERY OR ACCRUAL AFFECTING THE 2003 HISTORIC TEST YEAR.

AG -2 PENSION EXPENSES ARE UNCONTROLLABLE SUBJECT TO VARIOUS ECONOMIC AND MARKET CONDITIONS. THE COMPANY EXPENSES OVER THE LAST FOUR YEARS HAVE GREATLY EXCEEDED THE BENCHMARK ALLOWANCE. THE COMPANY HAS INTRODUCED A 401K COMPANY MATCHING PLAN AVAILABLE TO EMPLOYEES HIRED AFTER JANUARY 1, 2005. THESE EMPLOYEES WILL NOT BE ELIGIBLE FOR THE PENSION PLAN. THIS CHANGE HAS AND WILL CONTINUE TO HOLD DOWN INCREASING COSTS ASSOCIATED WITH THE CURRENT PENSION PLAN.

AG -3 THE 401K PLAN WAS FIRST AVAILABLE IN 2005. THE MOST CURRENT VERSION ALLOWS A COMPANY 100% MATCH FOR THE FIRST 2% OF EMPLOYEE'S CONTRIBUTION AND A 50% MATCH FOR THE NEXT 4% OF EMPLOYEE'S CONTRIBUTION. BY 2007 ALL UNION AND NON-UNION NEW EMPLOYEES WERE ELIGIBLE FOR THIS PLAN.

AG -4 PER FPSC ORDER NO.PSC-04-1110-PAA-GU THE COMPANY HAS BEEN WRITING OFF THE PREVIOUS NATURAL GAS RATE CASE EXPENSE OVER FOUR YEARS BEGINNING JAN 2005.

AG -5 CLAIMS VARY FROM YEAR TO YEAR. THE PRIOR CASE BASE YEAR WAS LOWER THAN NORMALLY EXPECTED AND THE PRESENT HISTORIC BASE YEAR WAS LARGER THAN AVERAGE. THE LOWER LEVEL IN 2003 WAS ALSO EFFECTED BY A REDUCTION IN THE SELF-INSURANCE RESERVE BALANCE DURING THAT YEAR AND A SMALL CHANGE IN THE ALLOCATION FACTORS FOR GENERAL LIABILITY INSURANCE FROM 2003 TO 2007.

SUPPORTING SCHEDULES: C-34 RECAP SCHEDULES: