BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Peoples Gas System, Inc.	DOCKET NO. 20230023-GU
Petition for approval of 2022 depreciation study, by Peoples Gas System,	DOCKET NO. 20220219-GU
Petition for approval of depreciation rate and subaccount for renewable natural gas facilities leased to others, by Peoples Gas System.	DOCKET NO. 20220212-GU
	FILED: August 18, 2023

MOTION AND NOTICE OF INTENT TO SEEK OFFICIAL RECOGNITION

Pursuant to Sections 120.569(2)(i), and 90.202, Florida Statutes (F.S.), and Rule 28-106-213(6), Florida Administrative Code (F.A.C.), the Citizens of the State of Florida (Citizens), by and through the Office of Public Counsel (OPC), respectfully request the Florida Public Service Commission (Commission) take official recognition of the following:

- Commission Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 080366-GU, *In re: Petition for rate increase by Florida Public Utilities Company.* **(Attachment A)**

- Composite exhibit of Commission orders concerning the Commission's policy regarding the correction of theoretical depreciation reserve imbalances. **(Attachment B)**

- Written customer comments submitted in Docket No. 2023-0023-GU. **(Attachment C)**

1) Pursuant to Section 120.569(2)(i), F.S., and Rule 28-106.213(6), F.A.C., a party may seek official recognition of matters set forth in Section 90.202, F.S. The Commission Orders are official actions of an official state agency of the State of Florida which the Commission may take official recognition of pursuant Section 90.202(5), F.S. The OPC recognizes that official recognition of the agency's orders may not be strictly required, but it is being undertaken to place parties on notice that the OPC intends to make use of them in this proceeding. *See Attachments A and B.*

2) The written customer comments are official records of the Commission which the Commission may take official recognition of pursuant to Section 90.202(6), F.S. *See Attachment C.*

3) This Motion also serves as Notice to the Commission and all parties of OPC's intent to request official recognition of the documents contained in Attachments A-C, in accordance with the Order No. PSC-2023-0128-PCO-GU.

4) OPC consulted with Peoples Gas System, Inc. and the Florida Industrial Power Users Group, and they do not object to this motion.

WHEREFORE, OPC requests that the Commission grant this Motion for Official Recognition.

Respectfully submitted this 18th day of August, 2023.

Walt Trierweiler
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/s/ Mary A. Wessling
Associate Public Counsel
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished this 18th day of August, 2023, by electronic mail to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Public Utilities Company.	DOCKET NO. 080366-GU ORDER NO. PSC-09-0375-PAA-GU ISSUED: May 27, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
KATRINA J. McMURRIAN
NANCY ARGENZIANO
NATHAN A. SKOP

NOTICE OF PROPOSED AGENCY ACTION ORDER
APPROVING IN PART A GAS RATE INCREASE
AND
REQUIRING ADDITIONAL FILINGS AND HOLDING REVENUES SUBJECT TO REFUND IN THE EVENT THE PLANNED MERGER IS CONSUMMATED

BY THE COMMISSION:

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

I. BACKGROUND

This proceeding commenced on December 17, 2008, with the filing of a petition for a permanent rate increase by Florida Public Utilities Company (FPUC or Company). The Company is engaged in business as a public utility providing distribution and transportation of gas as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. FPUC serves gas customers through two divisions: the Central Florida Division, consisting of portions of Seminole, Marion and Volusia Counties; and the South Florida Division, consisting of portions of Palm Beach, Broward and Martin Counties. Together, FPUC provides service to over 51,000 residential and commercial customers.

FPUC requested an increase in its retail rates and charges to generate $9,917,690 in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 8.74 percent or an 11.75 percent ROE (range 10.75 percent to 12.75 percent). The Company based its request on a projected test year ending December 31, 2009. In its petition, FPUC stated that this test year is the appropriate period to be utilized because it best represents expected future operations for use in analyzing the request for rate relief. FPUC has elected to

ATTACHMENT A

have its petition for rate relief processed under the proposed agency action (PAA) procedure authorized by Section 366.06(4), F.S.

We last granted FPUC a $5,865,903 rate increase by Order No. PSC-04-1110-PAA-GU.[1] In that order, we found the Company's jurisdictional rate base to be $59,171,674 for the projected test year ended December 31, 2005. The allowed rate of return was found to be 7.62 percent for the test year using an 11.25 percent return on equity (ROE).

FPUC also requested an interim rate increase in its retail rates and charges to generate $984,054 in additional gross annual revenues. Based on FPUC's calculations, the increase would allow the Company to earn an overall rate of return of 7.66 percent or a 10.25 percent ROE, which is the minimum of the currently authorized ROE range of 10.25 percent to 12.25 percent. The Company based its interim request on a historical test year ended December 31, 2007. By Order No. PSC-09-0123-PCO-GU, issued March 3, 2009, we granted the interim rate increase. The interim rates became effective for all meter readings made on or after 30 days from the date of the vote approving the interim increase. In the same order, we suspended the Company's proposed final rates and associated tariff revisions pending a final decision in this docket.

The Office of Public Counsel (OPC) intervened in this proceeding.[2]

Customer Meetings were held in West Palm Beach on March 26, 2009, and in Ocala and Deltona on April 2, 2009. A total of four customers spoke at the three meetings.

This Order addresses FPUC's requested permanent rate increase. We have jurisdiction pursuant to Sections 366.06(2) and (4), and 366.071, F.S.

II. TEST PERIOD

A. Projected Test Period

FPUC has requested that the projected test period for the 12 months ending December 31, 2009, be used as the test year. The Company used actual data for the 2007 historical base test year. This data served as a basis for developing its 2009 projected test year request. The 2008 projected test year was based on actual data through April 2008 plus projected data for the remainder of 2008. The projected 2009 test year was based on the projected level of customers, related revenues, expenses updated for cost changes and trending, capital expenditures, and the projected cost of capital. The projections through 2009 were reviewed by our auditors and analyzed by our staff.

[1] See Order No. PSC-04-1110-PAA-GU, issued November 8, 2004, in Docket No. 040216-GU, In re: Application for rate increase by Florida Public Utilities Company.
[2] See Order No. PSC-09-0010-PCO-GU, issued January 5, 2009, in Docket No. 080366-GU, In re: Petition for rate increase by Florida Public Utilities Company.

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. We find that the projected test period for the 12 months ending December 31, 2009, with our appropriate adjustments, is representative of the period in which the new rates will be in effect and is appropriate.

However, we are aware of the announcement of a merger with Chesapeake Utilities Corporation (Chesapeake), proposed to take place in the fourth quarter of 2009. Such merger could make the rates we are proposing in this Order to be inappropriate. Therefore, later in this Order, we have allowed for certain contingency provisions should the merger be consummated.

B. Bills and Therms

FPUC projected usage per customer for the 2009 test year separately for South Florida and Central Florida by rate class. The Company used monthly data from December 2004 through July 2008 to estimate the historical relationship between gas use per customer, normal weather conditions, natural gas prices (for certain rate classes), and time. These forecast assumptions appear to be appropriate. Based upon our staff's evaluation of the econometric equations used to produce the projected usage per customer, we also find that the projected usage per customer is appropriate for use in this case.

FPUC projected customer growth separately for South Florida and Central Florida by rate class. In Mr. Schneidermann's direct testimony, he states that most customer classes have experienced an increase in the number of customers since the previous rate case, but the rate of increase has declined in recent years. He says the Company also considered the recent troubles in the housing market and general economy, and that the Company is using a conservative estimate to assume that the number of customers will not decrease between 2008 and 2009. Based on a review of the 2009 projections by our staff, FPUC's South Florida and Central Florida General Managers, as well as the Company's Director of Marketing and Sales, we find the projections to be reasonable extensions of historical growth patterns.

After evaluating the Company's historical data and its projections for 2009, and taking the current economic climate into consideration, we find that the projected bills and therms are appropriate.

III. QUALITY OF SERVICE

Customer Meetings were held in West Palm Beach on March 26, 2009, and in Ocala and Deltona on April 2, 2009. The purpose of the meetings was to gather information from customers regarding the Company's quality of service and its request for a permanent rate increase. Two customers spoke at the West Palm Beach meeting, two customers spoke at the Deltona meeting, and no customers attended the Ocala meeting. There were no quality of service complaints expressed at the meetings. All of the residential customers who spoke at the meetings expressed concern over the rate increase. Also, a customer at the Deltona meeting was upset that the Company would not allow him to enter into a payment plan for the balance on his account.

In further investigation of quality of service, our staff analyzed all complaints taken by our Division of Service, Safety, and Consumer Assistance for the calendar year 2008. There were a total of 40 complaints, 30 involving billing complaints, and 10 involving service. All but three complaints were resolved in a timely manner. The number of complaints per customer compares favorably with other large Florida natural gas utilities. Also, we note that FPUC has not experienced an outage that falls under the reporting requirements of our Bureau of Safety since its last rate case, in 2004.

Considering all of the above, we find that FPUC's quality of service is satisfactory.

IV. RATE BASE

A. Allocations Attributable to Non-Regulated Business and Common Plant

The Company reviews its individual plant accounts each year to determine the appropriate allocations for non-regulated business and common plant. The Company's projected 2009 test year Minimum Filing Requirements (MFRs) data for plant in service, accumulated depreciation reserve, and depreciation expense were prepared using the 2008 allocation factors for non-regulated business and common plant. The 2009 allocation factors were not available at the time of filing.

The Company provided the 2009 allocation factors in response to our staff's data request. To reflect the 2009 allocation factors, plant in service and accumulated depreciation reserve shall be increased by $81,565 and $79,623, respectively. Also, depreciation expense shall be increased by $17,740.

B. Allocation of Common Electronic Data Processing (EDP) Equipment

In Audit Finding No. 12, our staff auditors found that there was an error in the allocation of common EDP equipment. As a result, the allocations to the electric and natural gas divisions were understated and the allocation to the propane division was overstated. The corrections required for the test year are increases to plant in service and the accumulated depreciation reserve of $90,819 and $52,067, respectively. Also, depreciation expense shall be increased by $9,616 to correct this error. The Company concurs with these adjustments.

C. Adjustments to Rate Base and Depreciation Expense and Amortization Expense for Bare Steel Replacement Program

The Company's bare steel replacement program was approved by this Commission in the Company's last rate case by Order No. PSC-04-1110-PAA-GU, issued November 8, 2004.[3] That Order stated:

> The bare steel replacement program as proposed by the Utility would replace all of the utility's existing bare steel mains and service lines with plastic pipe. Bare steel mains and service lines do not appear to have effective cathodic protection

[3] In Docket No. 040216-GU, In re: Application for rate increase by Florida Public Utilities Company, p.8.

> on them. Included in this total is approximately five miles of cast iron mains. Some of these mains and service lines have experienced corrosion and corrosion-related gas leaks.
>
> The utility's proposed program would replace all existing mains over a 75-year period beginning in 2005, at a total cost of $28,315,380, amortized at $377,538 per year. We find that the replacement period shall be shortened to 50 years to reflect the average useful life of the equipment. This change results in a yearly increase in amortization expense of $188,770 for a total of $566,308. Accumulated amortization for the projected test year is also increased by $94,385.[3]

According to the Company, 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. This emphasizes the need not only to continue the bare steel replacement program, but to enhance this program to include steel tubing replacements, recognizing the possible increased hazard from steel tubing.

The Company estimates that the total cost of the program is $37,386,365, from $28,315,380, as approved in the last rate case, an increase of $9,070,985. This increase is mainly due to greater material and installation costs associated with the replacement of steel pipe with plastic. Adding steel tubing to the replacement program accounts for only $642,660 of the program's total increased cost.

In the current rate case, the Company included an annual amortization of $623,106 for the bare steel mains, services, and steel tubing replacement program. The annual expense reflects the revised total cost of the replacement program and the Company's requested 60-year amortization period. These changes would increase the annual amortization expense from $566,308, as approved in the last rate case, to $623,106, or an increase of $56,798.

In the last rate case, the Company proposed a 75-year amortization period for the bare steel replacement program. Now, the Company is proposing a 60-year amortization period. Pursuant to Order No. PSC-04-1110-PAA-GU, we find that the Company's revised bare steel replacement program shall be approved with the exception that the amortization period shall remain at 50 years to reflect the average useful life of the equipment. This change results in a yearly increase in amortization expense of $181,419 over the program approved in the last rate case. It requires an adjustment to decrease the Company's plant in service and depreciation reserve by $67,503 and $716, respectively. It also requires an adjustment to increase amortization expense by $124,621 and decrease depreciation expense by $1,841.

Further, the Company shall file a report with our Division of Economic Regulation within 90 days of our final order in this rate case, showing the dollar amount and feet of plastic mains and services installed in 2005, 2006, 2007, and 2008, to replace the bare steel pipe retired in those same years. Thereafter, the Company shall file an annual status report by March 31 of each year showing the dollar amount and feet of plastic mains, services, and tubing installed during the previous calendar year to replace bare steel pipe and tubing retired that year.

D. Area Expansion Program (AEP) Deficiency

FPUC extends its facilities to provide service in accordance with the provisions of Rule 25-7.054, F.A.C. The rule requires extensions to be made at no cost to the customer when the capital investment necessary to extend the Company's facilities is less than the allowable construction cost. The allowable construction cost is equal to four times the estimated gas revenues from the facilities less the cost of gas. In the event the cost exceeds the allowable construction cost, the Company requires the customer(s) to make an advance in aid of construction, which has to be made up-front.

The 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. While Rule 25-7.054, F.A.C., is designed to address individual customers, the AEP is designed to address a group of customers that are part of an expansion project. The AEP allows the Company to add a surcharge that is billed to each participating customer until the excess construction cost is paid in full or a maximum period of 10 years, whichever comes first.

FPUC's existing AEP was originally approved in Docket No. 941291-GU.[4] The current program does not provide for a 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.

FPUC currently has 44 active AEP projects of which 38 are projected to have excess construction cost balances as of December 31, 2008. Due to the current economic conditions that have affected the new construction housing market, 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 has conducted an analysis of all 44 active AEP projects. The analysis showed that without an adjustment to the per therm surcharge, the unrecovered excess construction costs at the end of the 10-year collection period of each project, in total, will exceed $4,000,000.

The Company proposes to deal with this shortfall in two ways. First it proposes to increase the allowable surcharge rate, which is discussed below. Under the Company's proposed increase, the unrecovered excess construction cost balances would be reduced to $2,461,202 based on its original filing. However, the Company corrected the original filing in response to our staff's Data Request No. 70, increasing the unrecovered excess construction cost, after the proposed increase in the surcharge, from $2,461,202 to $2,478,621, or an increase of $17,419. The Company proposes to transfer the remaining balance of $2,478,621 to plant in service, increasing rate base as filed in the current rate proceeding. In the Company's last rate proceeding, we did not address the unrecovered excess construction cost balances associated with the AEP

[4] Order No. PSC-95-0162-FOF-GU, issued February 7, 1995, in Docket No. 941291-GU, In Re: Petition for approval of modification to tariff provisions governing main and service extensions by Florida Public Utilities Company.

FPUC is also proposing a new AEP, based on its experience in managing the existing AEP projects over the last 14 years. The Company's proposal for the new AEP, which is designed in part to reduce the underrecovery of cost in the future, is discussed below.

We believe that the AEP allows customers access to natural gas that they otherwise would not have been able to receive. Adding additional customers to the system helps spread common costs over a larger base, helping all customers.

Therefore, the unrecovered cost associated with the existing AEPs shall be allowed in rate base and recovered over the life of the property, and plant in service and accumulated depreciation reserve shall be increased by $2,478,621 and $31,998 respectively. This requires an adjustment to increase plant in service by $17,419, to correct the error in the Company's filing.

E. Account 252 - Customer Advances

Audit Finding No. 1 noted that FPUC made an error in Account 252 - Customer Advances for Construction forecast for 2009. The 2009 forecast was calculated by taking the 2007 historical average amount and applying the combined customer growth and inflation factor of 1.0274. The Company should have used the 2008 forecast average amount and the 2009 customer growth and inflation factor of 1.0274.

Therefore, Account 252 - Customer Advances for Construction shall be increased by $87,449 for the projected 2009 test year. The Company concurs with this adjustment.

F. Working Capital Allowance

In response to our staff's Data Request No. 49, the Company noted that the projected amounts shown in the MFRs represent the incorrect years for workman's compensation insurance. The corrected 13-month average for workman's compensation insurance for the 2009 test year is $88,748, compared to the Company's original filing of $106,340. Therefore, to correct this error, working capital shall be decreased by $17,592 for the 2009 test year.

Also, in response to our staff's Data Request No. 90, the Company noted that it had erroneously included $8,436 of Account 1210 -- Non-Utility Property in working capital for the 2009 test year. To correct this error, working capital shall be decreased by $8,436.

The total of these two adjustments is a decrease to working capital of $26,028.

G. Rate Base

Based on our above-noted adjustments, the appropriate 13-month average rate base for the 2009 projected test year shall be reduced from $73,747,220 to $73,262,885, as shown on Schedule 1.

ATTACHMENT A

V. COST OF CAPITAL

A. Accumulated Deferred Income Taxes (ADITs)

FPUC included ADITs of $2,773,818 in its 2009 projected test year capital structure. FPUC stated that ADITs arise from the normalization procedures of accrual accounting. The Company stated that its proposed treatment of ADITs capitalizes the tax benefit and amortizes the balance to income in equal installments over the life of the capital. The unamortized balance of ADITs is carried as a deferred liability. The Company also noted that 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 for purposes of determining regulated prices. The Company noted that the latter is the longstanding methodology adopted by this Commission, and it is the approach taken by FPUC in this filing.

We agree with the methodology used by FPUC to calculate the appropriate amount of ADITs to include in the Company's 2009 projected test year. Therefore, the appropriate amount of ADITs to include in the capital structure is $2,773,818.

B. Investment Tax Credits (ITCs)

FPUC included ITCs of $115,553 in its projected 2009 test year capital structure at a 9.38 percent cost rate. FPUC stated that ITCs arise from the normalization procedures of accrual accounting. The Company stated that its proposed treatment of ITCs capitalizes the tax benefit and amortizes the balance to income in equal installments over the life of the capital. The unamortized balance of ITCs is carried as a deferred liability. The Company also noted that it is common to include the liability in the capital structure for purposes of determining regulated prices. The Company stated that this treatment has been recognized by this Commission in the past, and it is the approach taken by FPUC in this filing.

We agree with the methodology used by FPUC to calculate the appropriate amount of ITCs to include in the Company's 2009 projected test year. We determined the appropriate cost rate for ITCs based on our approved capital structure and the ROE approved below. Therefore, the appropriate amount of ITCs to include in the capital structure is $115,553 at a cost rate of 8.72 percent.

C. Short-Term Debt

FPUC proposed a short-term debt cost rate of 4.71 percent based on the London Interbank Offer Rate (LIBOR) plus 156 basis points. The Company used a U.S. Federal Funds (Fed Funds) interest rate of 2.98 percent to estimate LIBOR. The Company noted that LIBOR has traded at an average of 17 basis points above the Fed Funds rate since January 2001. Therefore, the Company added 17 basis points to the Fed Funds rate to estimate a LIBOR rate of 3.15 percent. Next, the effective interest rate spread on outstanding daily balances, 80 basis points, was added to the 3.15 percent LIBOR rate to produce a cost rate of 3.95 percent. The Company then added 76 basis points to account for fees associated with the unused credit line, direct charges, and charges for outstanding balances. The use of this methodology produced the Company's recommended short-term debt cost rate of 4.71 percent.

We disagree with FPUC's proposed cost rate for short-term debt of 4.71 percent. The Company acknowledged that the Fed Funds rate was one percent at the time of the filing, and it is expected to hold steady over the near term due to the current slowdown in economic activity. Based on this Fed Funds rate, we find the appropriate estimate of the cost rate for short-term debt to be 2.73 percent, using FPUC's proposed methodology.

D. Long-Term Debt

FPUC proposed a cost rate for long-term debt of 7.90 percent. This cost rate is based on FPUC's five outstanding first mortgage series bonds that were issued over the 1988-2001 period. These issues have maturity dates ranging from 2018 to 2031 and carry coupon interest rates ranging from 4.90 percent to 10.03 percent. The Company's embedded cost rate is determined according to contemporary accounting conventions and accounts for the 2009 amortization schedule of issuance costs. The average net outstanding balance of long-term debt for 2009 also reflects unamortized issuance costs and sinking fund schedules. FPUC stated that the Company does not expect to issue additional long-term debt prior to 2010.

After review of FPUC's MFRs and supporting documentation, we find that FPUC's proposed cost rate of 7.90 percent accurately reflects the Company's long-term debt cost rate.

E. Return on Common Equity (ROE)

FPUC requested an ROE of 11.75 percent. The Company's currently-allowed ROE of 11.25 percent was authorized in Order No. PSC-04-1110-PAA-GU.

To support its proposed ROE, FPUC proffered a witness that provided the results of four capital valuation methods applied to two groups of companies identified as comparable in risk to FPUC. These methods include the Capital Asset Pricing Model (CAPM), Discounted Cash Flow (DCF) analysis, Risk Premium (RP) model, and an assessment of realized market returns. Because the PAA procedures were used, no other parties filed testimony in this docket regarding ROE.

1. ROE Models

Based on the statutory principles for determining the appropriate rate of return for a regulated utility set forth by the U.S. Supreme Court in its Hope and Bluefield decisions, the Company developed two groups of comparable risk utilities to determine the ROE for FPUC.[5] The first group, "Sample 1," consisted of eight mid-sized natural gas distribution companies (LDCs). These companies were selected based on business line and financial performance. FPUC also analyzed each company based on the following criteria: equity participation in total

[5] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

capital, coefficient of variation in earnings per share over five- and ten-year periods, CAPM beta, and variation in market returns. This criteria was also applied to the second group, "Sample 2," which is comprised of 11 mid-sized electric utilities (IOUs). FPUC identified the companies in each group using data from Value Line Investment Survey (Value Line), Ibbotson Associates (Morningstar), and web-based services such as Yahoo Finance, UBS Financial Services, and Zacks Financial Services.

FPUC's witness used a single-stage DCF model in analyzing each group. The 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 results of this analysis ranged from 13.13 percent to 14.97 percent for the LDCs and from 9.57 percent to 13.17 percent for the IOUs. These results included an adjustment for flotation costs of 6 percent or approximately 25 to 33 basis points. Based on this analysis, FPUC concluded a DCF-based ROE of 12.84 percent.

FPUC's witness also employed the CAPM in his analysis. The CAPM is a risk premium model that uses as inputs a risk-free rate, an overall return for the market, and beta. Beta is a measure of systematic risk, which is risk that cannot be diversified away. FPUC applied the CAPM to both groups of comparable companies. The results of this model ranged from 9.56 percent to 13.26 percent for the LDCs, and from 9.57 percent to 13.39 percent for the IOUs. These results included an adjustment for flotation costs of 6 percent or approximately 25 to 33 basis points. Based on this analysis, FPUC concluded a CAPM-based ROE of 11.42 percent.

The next approach FPUC's witness employed was an RP analysis. The underlying concept of the RP approach is that differences in perceptions of risks among financial assets such as equities and debt are revealed in differences between historical market returns. Thus, the Company stated that these differences can serve as a surrogate for the compensation of risk over future timeframes. The results of this approach ranged from 11.20 percent to 13.40 percent for both groups. These results included an adjustment for flotation costs of 6 percent or approximately 25 to 33 basis points. These results also included a small-size premia adjustment of 200 basis points. Based on this analysis, FPUC concluded an RP-based ROE of 12.30 percent.

Finally, FPUC's witness employed an assessment of realized market returns, or historical earned returns, over 5- and 10-year periods for both groups as well as for broader indices of companies in the natural gas and electric industries. The approach based on realized market returns assumes that if historical earned returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. The results of this assessment ranged from 9.81 percent for the natural gas industry to 10.40 percent for the electric industry. These results included an adjustment for flotation costs of 6 percent or approximately 25 for the natural gas companies and 33 basis points for the electric companies. FPUC concluded an ROE of 10.11 percent using this approach.

Based on the results of its analyses, FPUC determined a range of equity returns of 10.11 percent to 12.84 percent for the four approaches. The average of these indicated returns is 11.67 percent. The Company argued that its models were applied to mid-sized companies that, while not large, have much larger market capitalization than FPUC. It is the Company's view that the cost of equity is higher for small firms, other factors held constant. For these reasons, FPUC recommended the ROE be set at a level of 11.75 percent or higher.

2. Commission Analysis

The Company's ROE analysis relied heavily on dated information for estimates of the necessary inputs. The CAPM analysis relied on betas from 2007 and market returns based on historical, earned returns from 1970 through 2007. The timeframe relied on to determine the risk-free rate was not specified. There is considerable academic research documenting that risk premiums based on historical, earned returns are poor predictors of current market expectations. This deficiency also extends to the results of the RP model as it too relied on historical, earned returns.

The growth rate assumed in the DCF analysis for the LDCs was 10.14 percent. It is important to keep in mind that the ROE recognized for purposes of setting rates in this proceeding should be in line with the risk associated with the provision of regulated services. In the current economic environment, we do not believe an annual rate of growth in earnings this high is a reasonable approximation of the growth in earnings investors expect from regulated operations.

It is generally accepted that earned or realized returns can and do differ significantly from investor-required returns. Investors' required returns are a function of investors' expectations of risk and return going forward. Just because a particular investment earned a 5 percent or 15 percent return last year does not mean investors expect the same investment to earn a return of 5 percent or 15 percent the following year.

There is little doubt the recent disruption in the capital markets has exerted some degree of upward pressure on the current expectations of the market risk premium. However, we find this incremental increase in required return, whatever the appropriate amount may be, shall be applied to a contemporary estimate of the investor-required return. FPUC's witness identified a group of LDCs that he believes are comparable in risk to FPUC. Excluding the three LDCs with ROEs set in the mid 1990's, these utilities have authorized ROEs ranging from a low of 9.95 percent to a high of 10.70 percent. The average ROE for this group is 10.24 percent. We do not find the investor-required return for FPUC is 150 basis points greater than the average authorized return for the group of companies the Company identified as comparable in risk to FPUC.

3. Conclusion

We find that an authorized ROE of 10.85 percent is appropriate. This return is above the relevant average ROE for the group of LDCs the Company identified as comparable in risk to FPUC to compensate for the recent disruption in the capital markets. We believe this level of return also compensates for the financial risk associated with FPUC's capital structure. For the reasons discussed above, the authorized ROE for FPUC shall be set at 10.85 percent, with a range of plus or minus 100 basis points.

F. Capital Structure

In its MFRs, FPUC filed a projected capital structure on both a 13-month average and year-end basis. Although the Company used a 13-month average capital structure for purposes of its request for a rate increase, the Company made an argument to support consideration of a year-end capital structure for purposes of this proceeding. FPUC's stated reason for requesting the year-end capital structure is to reflect the issuance of new shares of common equity in mid-year 2009. Use of a year-end capital structure produces an overall cost of capital that is 20 basis points greater than the rate of return indicated by a 13-month average capital structure. This incremental difference represents approximately $240,000 in annual revenue requirements. The equity ratio using FPUC's alternatively proposed year-end capital structure is 52.75 percent, which is 4.62 percentage points higher than the 13-month average capital structure equity ratio of 48.13 percent.

The Company acknowledged that use of a year-end capital structure is a departure from our long-standing policy of using a 13-month average capital structure. By using a projected test year, the Company's projected equity issuance would be partially recognized in the rate setting process. However, we find that the Company shall use a 13-month average capital structure such that it corresponds with its 13-month average rate base, so that all the components are consistent. Furthermore, we do not find that FPUC has demonstrated sufficient extenuating circumstances, such as extraordinary growth or inflation, to merit a divergence from the standard practice of using a 13-month average capital structure. For these reasons, we find that FPUC shall use a 13-month average capital structure, to be consistent with its use of a 13-month average rate base and our past practice as approved in Order No. 10449.[6]

Additionally, the Company used a capital structure excluding the unregulated subsidiary Flo-Gas balances in the capital structure for purposes of its request for a rate increase. However, FPUC argued in support of including the unregulated subsidiary Flo-Gas balances in the capital structure, because it believes these funds cannot be earmarked for specific purposes. FPUC stated that this treatment places the Company's unregulated propane operations at a competitive disadvantage to other propane companies as justification for the inclusion of unregulated Flo-Gas balances in the capital structure. In reconciling rate base and capital structure, our practice regarding non-utility investment is stated below:

> . . . we believe all non-utility investment should be removed directly from equity when reconciling the capital structure to rate base unless the utility can show, through competent evidence, that to do otherwise would result in a more equitable determination of the cost of capital for regulatory purposes. In the case of Gulf, we believe that the non-utility investment should be removed from equity. This will recognize that non-utility investments will almost certainly increase a utility's cost of capital since there are very few investments that a utility can make that are of equal or lower risk. Removing non-utility investments directly from equity

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[6] Order No. 10449, issued December 15, 1981, in Docket No. 810035-TP, In re: Petition of Southern Bell Telephone and Telegraph Company for a rate increase.

> recognizes their higher risks, prevents cost of capital cross-subsidies, and sends a clear signal to utilities that ratepayers will not subsidize non-utility related costs.[7]

Based on these reasons, FPUC shall continue to remove non-utility investments directly from equity, recognizing their higher risks and preventing cross subsidization through the cost of capital. This treatment is consistent with our past practice and our treatment in FPUC's most recent rate cases.[8]

G. Cost of Capital

For its projected test year capital structure, FPUC allocated investor capital amounts from its consolidated 13-month average capital structure to its gas division. FPUC specifically identified customer deposits, deferred taxes, and investment tax credits for the gas division in developing the capital structure. The Utility's resulting overall cost of capital calculation was 8.74 percent, which was based on an equity ratio as a percentage of investor-supplied capital of 48.13 percent and an ROE of 11.75 percent.

As discussed above, the appropriate amount of ADITs to include in FPUC's capital structure is $2,773,818, and the appropriate amount of ITCs to include in the capital structure is $115,553 at a cost rate of 8.72 percent. Also, the rates for short-term debt, long-term debt, and ROE are 2.73 percent, 7.90 percent, and 10.85 percent, respectively.

The net effect of our adjustments is a reduction in the overall cost of capital from the 8.74 percent return requested by the Company to a return of 8.17 percent. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2009, we find that the appropriate weighted average cost of capital for FPUC is 8.17 percent, as shown on Schedule 2.

VI. NET OPERATING INCOME

A. Non-Regulated Business Expense

The Company allocated the incorrect amount of payroll for merchandise and jobbing customers to its non-regulated operations in 2007 and 2008. In both years, warranty programs were counted as separate customers in addition to being counted as merchandise and jobbing customers. This resulted in an overstatement of the number of non-regulated customers. Also, the time studies used by the Company were based on historical periods that did not take into account the dramatic slowdown in the housing and construction industry that began in late 2007. To correct for these errors, the Company increased the expenses allocated to Account 912.1 -- Demonstrating and Selling expenses for its regulated natural gas operations in 2008 and 2009 by

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[7] Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Petition of Gulf Power Company for an increase in its rates and charges, p. 21.

[8] Order No. PSC-04-1110-PAA-GU, issued November 8, 2004, in Docket No. 040216-GU, In re: Application for rate increase by Florida Public Utilities Company; and Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company.

an estimated $100,000. The Company indicated that it would record the actual amount required for this adjustment based on updated customer counts and time studies late in 2008.

In Audit Finding No. 4, our staff auditors noted that subsequent to the filing, FPUC calculated the actual effect based on updated customer counts and time studies in December 2008, which increased regulated natural gas expenses for 2008 by $24,881. The Company trended the payroll costs in this account at 5.5 percent from 2008 to 2009. This produced a 2009 projected test year amount of $26,249, versus the $100,000 the Company had estimated.

In light of these circumstances, Account 912.1 – Demonstrating and Selling expenses shall be reduced by $73,751 for the projected 2009 test year. The Company concurs with this adjustment.

B. Franchise Fees

The Company failed to remove both franchise fee revenue and franchise fee expense from its projected 2009 test year operations. Franchise fees are billed as a separate line item on the customers' bills. Franchise fees are not considered a general expense applicable to all of the Company's customers. The appropriate franchise fee rate is applied to only those customers' bills that reside within the franchising entity's boundaries. Therefore, neither the revenues nor the expenses related to franchise fees shall be included in the income statement for ratemaking purposes. Both operating revenues and taxes other than income shall be reduced by $1,441,002 for the 2009 projected test year. Since these amounts offset each other, there is no effect on the amount of net operating income.

C. Gross Receipts Tax

The Company failed to remove both gross receipts tax revenue and gross receipts tax expense from its projected 2009 test year operations. Although the gross receipts tax is applicable to all of the Company's customers, it is billed as a separate line item on the customers' bills. Therefore, neither the revenues nor the expenses related to the gross receipts tax shall be included in the income statement for ratemaking purposes. Both operating revenues and taxes other than income shall be reduced by $2,315,886 for the projected 2009 test year. Since these amounts offset each other, there is no effect on the amount of net operating income.

D. Inflation Trend Factor

FPUC used nationally known sources to derive its Consumer Price Index (CPI) trend factor of 2.7 percent. Because the trend factor was developed from mid-2008 data, the dramatic fall in energy prices and the economy were not foreseen. Although the CPI has fallen since 2008, the State's National Economic Estimating Conference in February 2009 forecast that the CPI will reach 2.6 percent in 2010 and afterwards will not fall below 2.7 percent going out to 2019. Therefore, we find FPUC's trend factor of 2.7 percent is reasonable for use in this docket.

E. Account 903 - Customer Records and Collections?

Audit Finding No. 3 disclosed that the December 2007 invoice from the entity that prepares and mails the bills was not accrued at year end. The December invoice, which totaled $42,018, was charged to a clearing account. The clearing account was allocated among the operations with 54 percent, or $22,690, being charged to natural gas. The December 2007 amount was trended up by 8.15 percent to arrive at $24,539 for 2009. Based on the above, we find Account 903 – Customer Records and Collections shall be increased by $24,539 for the 2009 projected test year. The Company concurs with this adjustment.

F. Account 904 - Uncollectible Accounts

The Company calculated Account 904 - Uncollectible Accounts expense for the 2009 test year based on the 2008 expense increased for the projected 2009 write-offs. The 2009 write-offs were expected to increase due to anticipated higher customer bills driven by the Purchased Gas Adjustment (PGA) clause. The Company reasoned that a projected increase in customer bills, due to a higher PGA, coupled with the inability to increase customer deposits until at least twelve months of higher bills had been rendered, would cause the write-off of bad debts to increase.

The Company's calculation was based on an average of two typical bills. The typical bills were for a residential customer using 25 therms and for a commercial customer using 200 therms. The average of these two bills was estimated for the 12 months ended September 30, 2008, and the 12 months ended September 30, 2009. The Company determined that there was an 111 percent increase in the amount to be written off, net of the deposit, between the two periods. The deposit amount was held constant for both periods to reflect the Company's inability to increase customer deposits in step with the increase in the typical bill. The Company applied the 111 percent increase to the 2008 uncollectible expense to determine the 2009 amount. In addition, it applied 2 percent for customer growth, plus 10 percent to reflect the effects of the current economic downturn. The Company's total proposed projected Uncollectible Accounts expense for 2009 is $639,175, which is an increase of $369,187 over 2008.

Traditionally, uncollectible expense has been calculated based on total historical write-offs expressed as a percentage of total revenue. This percentage is then applied to the test year revenue to determine the uncollectible expense. If revenue increases in the test year then the allowed uncollectible expense will also increase.

Although we are aware of the current economic conditions and the impact that it is having on uncollectible accounts, we find that using total actual write-offs and total actual revenue gives a more complete view of uncollectible accounts expense as opposed to only reviewing typical bills. Therefore, we have used the year 2008 average net write-off and increased this percentage by 10 percent to recognize the effect of the current downturn in the economy. The 2008 net write-off percentage was .46 percent and when increased by 10 percent equals .51 percent. The year 2008 reflects the most recent known conditions and appears reasonable when compared with other years. For example, the net write off percentage for 2006 was also .46 percent. Applying the .51 percent net write-off percentage to the 2009 projected test year revenues of $102,416,152, we calculate an uncollectible accounts expense of $522,322 for the test year. This necessitates an adjustment to decrease Account 904 - Uncollectible Accounts expense by $116,853.

We note that this adjustment is for ratemaking purposes only. For surveillance, annual report, and other reporting purposes, the Company's actual bad debt expense shall be reported.

G. Misclassified Travel Expenses

Audit Finding No. 9 revealed that there were transactions inappropriately allocated between the different companies and divisions. Invoices totaling $2,610 were found in 2007 expenses that were allocated 75 percent or $1,957 to natural gas and should have been charged to electric. Using the compounded inflation factor for 2007 to 2009 of 6.97 percent, we increased the 2007 amount of $1,957 to a 2009 amount of $2,093. Therefore, Account 912 - Demonstration and Selling expenses shall be decreased by $2,093 for the test year. The Company concurs with this adjustment.

H. Account 913 - Promotional Advertising Expense

In Audit Finding No. 2, our staff auditors noted that FPUC paid $52,000 in 2007 for a contract with St. Joe Arvida homes. Because the advertisement only includes the FPUC logo, it does not meet the requirements of Rule 25-17.015(5), F.A.C., for recovery through the Energy Conservation Cost Recovery clause (ECCR). Since it does not qualify for recovery through the ECCR, the Company charged this contract to Account 913 - Promotional Advertising expense. The amount was trended to $56,238, in the 2009 forecast.

In its response to the Audit Finding, the Company stated that the $56,238 forecast for 2009 expenses should be included in the Company's base rate request because the advertising was valuable, cost effective, and beneficial to all customers. Further, while the FPUC logo was relatively small, the effort made by the developer in utilizing the advertising dollars was very effective. The money went into training the developer's sales staff and promoting natural gas in Victoria Park. The Company contends that the advertising was more successful than FPUC's broad-based conservation advertising campaign across a greater number of customers.

In Order No. PS-07-0671-PAA-GU, issued August 21, 2007, concerning an investigation into the 2005 earnings of FPUC, we stated:

> The audit disclosed that a $52,000 payment was made to St. Joe/Arvida Homes for co-op advertising. This payment was booked as a promotional advertising expense. The ad promoted the sale of new homes in the St. Joe development at Victoria Park in the Deland, Florida area. The only reference to FPUC is a small generic FPUC logo in the lower left hand corner of the ad. The ad does not contain any safety, conservation, instructional or informational material regarding the use of natural gas. It appears that the sole purpose of the ad is to induce the public to purchase homes in Victoria Park.

> . . . Our general policy regarding advertising expenses is to allow advertising that contains informational and instructional material. This type of advertising primarily conveys information as to what the utility urges or suggests customers should do in utilizing gas service to protect health and safety, to encourage environmental protection, to utilize their gas equipment safely and economically, or to conserve natural gas. Advertising that is considered to be institutional, goodwill, promotional or image-enhancing is usually not allowed for revenue requirement purposes.[9] We find that the Victoria Park ad does not meet the criteria for inclusion as an advertising expense for the purposes of determining the amount of overearnings for 2005. Therefore, advertising expenses shall be reduced by $52,000.[10]

Based on the above, Account 913 - Promotional Advertising expense shall be reduced by $56,238 for the 2009 test year.

I. Account 920 - Administrative and General Salaries for Officer's Salaries

Audit Finding No. 5 noted that the forecast for Account 920 - Administrative and General Salaries, included an increase of 11.5 percent for 2008 and 2009. The increase was based on a study done during the last rate case for the electric division that showed that the officers' salaries were lower than the rest of the industry. However, the Board of Directors gave the officers an eight percent increase in 2008, and a three percent increase has been authorized for 2009. The Company has revised its estimated salaries for these three employees from $871,971 to $786,212 for the year 2009. The difference of $85,759 times the 52 percent allocation to natural gas results in a decrease of $44,595.

Account 920 - Administrative and General Salaries shall be decreased by $44,595 for the projected 2009 test year. The Company agreed with these findings based on the known facts at the time of the audit (report dated March 4, 2009). However, the Company did point out that the Board of Directors could award additional compensation to these executives for 2009.

J. Account 935 – Maintenance of General Plant

In the test year, the Company included the cost associated with the new flooring for the corporate office. The anticipated cost for flooring is $100,000, based on a vendor quote. The total allocation was based on a four-year recovery period. The $25,000 annual cost, based on the four-year recovery period, was allocated to natural gas based on common plant allocation factors, and totals $13,500.

In response to a data request, the Company disclosed that the new floor has an eight-year life. The Company used the four-year recovery period because this is the period it expects the new rates to be in effect. We find that the flooring shall be amortized over the eight-year life of

[9] Order No. PSC-94-1519-FOF-GU, issued December 9, 1994, in Docket No. 940620-GU, In re: Application for a rate increase by Florida Public Utilities Company. [Citation appears in Order No. PSC-07-0671-PAA-GU].
[10] Order No. PSC-07-0671-PAA-GU, issued August 21, 2007, in Docket No. 070107-GU, In re: Investigation into 2005 earnings of the gas division of Florida Public Utilities Company.

the floor. This results in an adjustment to decrease Account 935 – Maintenance of General Plant by $6,750.

K. Storm Damage Accrual

The Company is requesting an annual storm damage accrual of $87,000 and a total for Account 924 - Property Insurance of $214,531 for the 2009 test year. FPUC began making accruals of $18,000 per year to the storm damage reserve in 1996 and accumulated a balance of $59,070 before ceasing the accruals in January 2003. In its 2005 rate case, FPUC did not request permission to make further accruals to its storm damage reserve, and we did not allow any accrual in the setting of new rates.[11]

The only charge made to the storm damage reserve from 1996 until 2004 was a charge of $62,430 related to Hurricane Floyd in 1999. Over an eight-year period (1996–2003), the average annual charge to the storm damage reserve was $7,804.

On December 28, 2004, FPUC filed a petition seeking authority to implement a Storm Cost Recovery Clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, and Jeanne that struck its service territory in 2004. In Order No. PSC-05-1040-PAA-GU, we determined that the amount of storm costs for the three storms was $543,602. Also in that proceeding, we ordered that $117,773 of overearnings for the year 2002, be credited to the storm damage reserve account to establish a reserve amount for future storms.

In Order No. PSC-07-0671-PAA-GU, we found that:

> Given the $534,602 of storm damage sustained by the Company during 2004, the current balance in the storm damage reserve is inadequate to offset damages from any future storms. Therefore, we find that the establishment of an adequate storm damage reserve is a reasonable disposition of the remaining amount of the 2005 excess earnings.
>
> . . . The remaining amount of the 2005 excess earnings shall be applied to the storm reserve to cover future storm-related costs.[12]

The net amount recorded to the storm damage reserve as a result of the 2005 overearnings was $612,774.

In the matter of FPUC's 2006 earnings, we determined that the excess earnings of $176,144 would be applied to increase the storm reserve balance. We further noted that the

[11] Order No. PSC-05-1040-PAA-GU, issued October 25, 2005, in Docket No. 041441-GU, In re: Petition for approval of storm cost recovery clause to recover storm damage costs in excess of existing storm damage reserve, by Florida Public Utilities Company.

[12] Order No. PSC-07-0671-PAA-GU, issued August 21, 2007, in Docket No. 070107-GU, In re: Investigation into 2005 earnings of the gas division of Florida Public Utilities Company.

annual storm reserve accrual could be an issue in the Company's forthcoming rate case in Docket No. 080366-GU.[13]

The Company's storm reserve balance as of September 30, 2008, was $788,918, and has been collected from customers through the Company's overearnings. This amount is in excess of the storm damage of $543,602, which was incurred as a result of Hurricanes Charley, Frances, and Jeanne that struck its service territory in 2004. The storm damages in 2004 represent one of the worst years for storm damage for the utility industry in Florida's history.

FPUC did not file a study in support of its request to establish an annual storm damage accrual of $87,000 or a target level for the reserve. Instead, the Company estimated the replacement basis for all mass property items, which are subject to some level of damage, to be $164 million. It then chose one-half-of-one percent of the $164 million as its target reserve level of $820,118. Comparing the current reserve balance of $788,918 to the target leaves a reserve deficiency of $31,200. The Company then spread this $31,200 over eight years to arrive at $3,900 per year. It added the $3,900 deficiency to an average annual storm damage of $83,000, based on actual storm damage for the 8-year period of 2000 through 2008. The Company arrived at $87,000 per year as its required accrual for storm damage.

The Company's total 2009 projection for Account 924 - Property Insurance was based on the $87,000 annual accrual for storm damage discussed above, plus historical transactions for this account in 2007, adjusted for inflation. Also, any previous storm damage cost in the account was removed. However, in its calculations, the Company failed to remove $81,080 related to electric operations from the account.

We find that the Company shall begin to build its storm reserve through an annual accrual process rather than through one-time entries resulting from excess earnings. However, we further find that the current balance may be near its optimal level given the current reserve balance of $788,918, compared to the $543,206 of storm damage that was incurred as a result of three hurricanes in 2004. Based on the above, we find the appropriate annual accrual amount to be $6,000, with a target level of $1,000,000. These amounts can be reviewed again in the Company's next rate case.

Also, we find that Account 924 - Property Insurance shall be decreased by $81,080 to eliminate the expenses related to electric operations. To reflect our approved storm damage accrual of $6,000, Account 924 - Property Insurance shall be decreased by $81,000 from the Company's requested $87,000. This results in a total adjustment to decrease Account 924 - Property Insurance by $162,080. Also, working capital shall be increased by $81,040.

L. Account 926.5 - Employee Benefits Medical

The Company's projections for Account 926.5 - Employee Benefits Medical were based on information provided by its insurance carrier. The insurance carrier estimated increases in the

[13] Order No. PSC-08-0697-PAA-GU, issued October 20, 2008, in Docket No. 080514-GU, In re: Investigation into 2006 earnings of the gas division of Florida Public Utilities Company.

Company's medical costs of 11.5 percent for 2008, 6.5 percent for 2009, and 15 percent for 2010 through 2012. The Company projected its 2008 medical costs based on an increase of 11.5 percent over the 2007 actual amount consistent with the information provided by the insurance carrier. However, even though the insurance carrier provided a specific estimate of a 6.5 percent increase for the year 2009, the Company based its projection on the average increase expected over the 4-year period from 2009 through 2012.

The Company explained the 2009 increase by stating that:

> 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.

The Company's adjustment is based on increases in medical cost that will occur during the three years beyond the end of the test year. However, the Company has not recalculated all of the elements that make up its operations for this same period. This produces an adjusted test year with information related to rate base, net operating income, and capital structure based on time periods that do not match.

In Audit Finding No. 7, our staff auditors expressed concerns as to whether FPUC should be allowed to project its insurance costs to 2012. All other expenses were projected through 2009.

We find that the test year medical costs shall be based on the specific estimate of a 6.5 percent increase for the year 2009 provided by the Company's insurance carrier. The Company's 2008 medical cost is projected to be $958,713. Increasing this amount by 6.5 percent produces $1,021,029, which is a decrease of $235,805 compared to the Company's original filing.

M. Rate Case Expense

The Company originally requested $844,080 in rate case expense, amortized over four years. As a part of its analysis, our staff requested an updated expense through February 28, 2009, with supporting documents as well as an estimated amount to complete the case. The Company submitted a revised estimate of rate case expense through completion of the PAA process of $606,643.

The components of the Company's estimated rate case expense are as follows:

	Original Filing	Rate Case Expense Actual as of 2/28/2009	Additional Estimated	Total Revised
Consultants	$576,250	$369,762	$73,079	$442,841
Legal Fees	107,500	12,430	30,319	42,749
Travel Expenses	34,080	1,790	10,700	12,490
Paid Overtime	39,000	422	33,000	33,422
Other Expenses	87,250	15,840	56,300	72,140
Total	$844,080	$400,244	$203,398	$603,643

Based upon review of the requested actual expenses and supporting documentation and of the estimated expenses, we find those expenses are reasonable.

In previous rate cases involving FPUC, we have allowed one half of the balance of unamortized rate case expense to be included in working capital as a part of rate base. We have a long-standing policy in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases.[14] The rationale for this position was to adopt a sharing concept whereby the cost of a rate case would be shared between the ratepayer and stockholder, i.e., include the expense in the O&M expenses, but not allow a return on the unamortized portion. This approach recognizes that both the stockholders and the ratepayers benefit from a rate proceeding. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.

While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital, based on a simple average. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period.[15] While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.

In Docket No. 910778-GU, the issue was argued fully and we reaffirmed our long-standing policy of excluding unamortized rate case expense from working capital in electric and gas rate cases.[16] Order No. PSC-92-0580-FOF-GU stated that unamortized rate case expense is excluded from working capital "in an effort to reflect a sharing of rate case expenses between the stockholders and the ratepayers since both benefit from a rate case proceeding." The inclusion of

[14] Order No. 14030, issued January 25, 1985, in Docket No. 840086-EI, In Re: Application of Gulf Power Company for authority to increase its rates and charges; Order No. 16313, issued July 8, 1986, in Docket No. 850811-GU, In Re: Petition of Peoples Gas System, Inc. for authority to increase its rates and charges in Hillsborough County; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In Re: Application of Gulf Power Company for a rate increase.
[15] Rule 25-30.4705, F.A.C.
[16] Order No. PSC-92-0580-FOF-GU, issued June 29, 1992, in Docket No. 910778-GU, In re: Petition for a rate increase by West Florida Natural Gas Company, p. 15.

unamortized rate case expense in working capital in FPUC's case is an exception to our long-standing policy.

FPUC was initially allowed to include rate case expense in working capital in its 1993 rate proceeding.[17] At that time, we found that the exclusion of the unamortized portion of rate case expense from working capital is a partial disallowance and concluded that rate case expense is a necessary cost of doing business. The order included a concurring opinion by Commissioner Lauredo, where it was stated that:

> . . . his decision was based solely on the facts and circumstances involved with this case. He emphasized this result should not be standing Commission policy and that no precedential value should be assigned to his concurrence.[18]

Based on the above, we find that the appropriate rate case expense is $603,643, amortized at the rate of $150,911 over four years. This results in a reduction to Account 928 – Regulatory Commission expenses of $60,109. In addition, none of the unamortized rate case expense shall be included in working capital for the projected test year. As a result, working capital shall be reduced by $324,270.

N. Accumulated Depreciation and Depreciation Expense

We approved our staff's recommendation for the new depreciation study filed by the Company in Docket No. 080548-GU.[19] The approved rates have the following effect on depreciation expense for the 2009 test year:

Table 1 - Depreciation Expense

Increase in Depreciation Expense for Natural Gas Assets	$178,133
Increase in Depreciation Expense for Shared Common Assets allocated to Natural Gas	21,383
Increase in Depreciation Expense for Non-Regulated Assets (Decrease in depreciation on non-regulated plant creates increase for regulated operations)	3,381
Decrease in Depreciation Expense for AEP Assets	(2,460)
Increase in Depreciation Expense for Bare Steel Replacement Program	3,748
Increase in Depreciation for Land Recovery Rights	1,411
Total Increase in Depreciation Expense	$205,596

The approved depreciation rates have the following effect on the accumulated depreciation reserve for the 2009 test year:

[17] Order No. PSC-94-0170-FOF-EI, issued February 10, 1994, in Docket No. 930400-EI, In re: Application for a rate increase for Marianna Electric Operations by Florida Public Utilities Company, p. 10.
[18] Ibid, pp. 10-11.
[19] Order No. PSC-09-0229-PAA-GU, issued April 13, 2009, in Docket No. 080548-GU, In re: 2008 depreciation study by Florida Public Utilities Company.

Table 2 - Accumulated Depreciation Reserve

Increase in Depreciation Reserve for Natural Gas Assets	$97,007
Increase in Depreciation Reserve for Shared Common Assets allocated to Natural Gas	54,380
Decrease in Depreciation Reserve for Non-Regulated Assets (Decrease in depreciation on non-regulated plant creates decrease for regulated operations)	(31,326)
Decrease in Depreciation Reserve for AEP Assets	(1,230)
Increase in Depreciation Reserve for Bare Steel Replacement Program	123
Total Increase in Depreciation Reserve	$118,954

O. Vacant Positions

In its original filing, the Company included projected expenses of several new or vacant positions to be filled by the beginning of the 2009 projected test year. A review of the pre-filed testimony supporting the positions and written job descriptions for each job shows that the addition of these positions is appropriate. However, we find that an adjustment shall be made to reflect the timing of when these positions will be filled.

In response to our staff's Data Request No. 91, the Company provided the status of each of the original open positions including actual salary. Nine of the eleven positions that still remain open as of April 2009 were described as expecting to be filled in two to six months. If the Company does take an additional six months to fill these positions they would only be filled for approximately three months of the 2009 projected test year. There is no certainty that these positions will be filled at all.

Based on the above, we find that 75 percent of the projected salaries, or $190,505 associated with these positions, shall be removed from the test year expenses. This decrease shall be distributed to the following accounts as follows:

Account 870	$32,625
Account 880	32,625
Account 887	21,763
Account 892	21,763
Account 903	37,500
Account 912	35,646
Account 925	8,583
Total	$190,355

P. Account 408.1 – Taxes Other Than Income Taxes

Audit Finding No. 10 states that FPUC is constructing a building for the South Florida Operations Facility that is not scheduled to be placed in service until mid-2010. However, the associated property taxes for this building, in the amount of $114,079, were included in the 2009 projected test year.

The Company discussed the property tax expense in its direct testimony as follows:

> We now anticipate completion of the facility in 2010, however, we feel it is appropriate to seek recovery of the increase [in property taxes] 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, . . . 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.

The Company has requested that we consider granting special rate relief for recovery of the South Florida Operations Center, to be effective after the in-service-date of the facility which is expected to be in September of 2010. We find that Account 408.1 - Taxes Other Than Income Taxes shall be reduced by $114,079, and we will address this expense in the new South Florida Operations Facility rate relief issue discussed below.

Q. Taxes Other Than Income Taxes Due to Common Plant Allocations

In Audit Finding No. 8, our staff auditors noted that property taxes associated with common plant were not allocated consistent with the allocation of the common plant. In its response to the audit finding, the Company agreed with the concept of this finding, but recommended using a slightly different percentage in the calculation. The Company recommended using the 2008 net plant of each division excluding vehicles. The Company noted that vehicles are not part of its property tax base. We agree. Therefore, Account 408.1 – Taxes Other Than Income Taxes shall be decreased by $53,265 for the test year, based on the percentage recommended by the Company.

Our staff auditors also noted in Audit Finding No. 8 that property taxes associated with non-regulated plant, located in the natural gas divisions, were not allocated consistent with the allocation of the non-regulated plant. In its response to the audit finding, the Company agreed with the concept of this finding, but again recommended using the 2008 net plant allocated to non-regulated excluding vehicles. The Company noted that vehicles are not part of its property tax base. Again, we agree. Account 408.1 – Taxes Other Than Income Taxes shall be reduced by $13,098 for the test year, based on the percentage recommended by the Company.

The total of these two adjustments results in a decrease in Account 408.1 – Taxes Other Than Income Taxes of $66,363 for the test year.

R. Income Tax Expense

Based on our adjustments above, we find the requested total income tax expense of a negative $1,529,681 (current, deferred, and ITCs) shall be increased by $344,852, resulting in an adjusted total of a negative $1,184,829 for the 2009 projected test year as shown on Schedule 3.

Amount Requested	($1,529,681)
Commission Adjustments:	
Effect of Other Adjustments	281,830
Interest Synchronization	63,022
Total Adjustments	344,852
Commission Adjusted Amount	($1,184,829)

S. Net Operating Income

Based on all the above, we find the appropriate Net Operating Income to be $740,020, as shown on Schedule 3.

VII. REVENUE REQUIREMENTS

A. Revenue Expansion Factor and Net Operating Income Multiplier

The only change in the Net Operating Income Multiplier filed by the Company is the rate used for bad debt, as discussed above. A comparison between the Company and our findings is shown below:

Line No.	Description	Company	Commission
1	Revenue Requirement	100.00%	100.00%
2	Gross Receipts Tax Rate	0%	0%
3	Regulatory Assessment Rate	.50%	.50%
4	Bad Debt Rate	.73%	.51%
5	Net Before Income Taxes	98.77%	98.99%
	(1)-(2)-(3)-(4)		
6	State Income Tax Rate	5.50%	5.50%

Line No.	Description	Company	Commission
7	State Income Tax (5x6)	5.43%	5.44%
8	Net Before Federal Income Tax (5-7)	93.34%	93.55%
9	Federal Income Tax Rate	34.00%	34.00%
10	Federal Income Tax (8x9)	31.73%	31.81%
11	Revenue Expansion Factor (8)-(10)	61.60%	61.74%
12	Net operating Income Multiplier 100%/Line 11	1.62330	1.6197

B. Annual Operating Revenue Increase

Based on our calculations above, we calculate the appropriate annual operating revenue increase to be $8,496,230, as shown on Schedule 5 for the projected test year.

VIII. COST OF SERVICE AND RATE DESIGN

A. Revenues From Sales of Gas by Rate Class

A review of the Company's calculations and estimated revenues from sales of gas by rate class at present rates for the projected test year shows that they are appropriate, and no adjustment is necessary.

B. Cost of Service Methodology to Be Used in Allocating Costs

The appropriate cost of service methodology to be used in allocating costs to the various rate classes is reflected in the cost of service study contained in Schedule 6, pages 1-21. The purpose of a cost of service study is to allocate the total costs of the utility system among the various rate classes. The results of the cost of service study are used to determine how any revenue increase granted by this Commission will be allocated to the rate classes. Once this determination is made, rates are designed for each rate class that recover the total revenue requirement attributable to that class. In rate design, the customer charge is typically determined first, with the per-therm energy charge being the fall-out charge.

The Company's proposed cost of service study is contained in MFR Schedule H. Our study differs in several respects from the Company's filed study. The study reflects our adjustments to rate base, rate of return, revenues, expenses, and resulting operating revenue increase as shown above.

C. Customer Charges

The customer charge is a fixed charge that applies to each customer's bill, regardless of the quantity of gas used for the month. The customer charge is typically designed to recover costs such as metering and billing that are incurred whether any gas is consumed or not.

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

Proposed Rate Class	Current Customer Charges	Company-Proposed Customer Charge	Commission Approved Customer Charge
RS	$8.00	$12.00	$11.00
GS-1/GSTS-1	$15.00	$20.00	$20.00
GS-2/GSTS-2	$15.00	$33.00	$33.00
LVS/LVTS	$45.00	$90.00	$90.00
IS/ITS	$240.00	$240.00	$280.00
RS-GS	$18.72	$22.45	$21.25
CS-GS	n/a	$36.31	$35.81

The approved customer charge for the IS/ITS class is higher than FPUC's proposed charge based on the customer unit cost shown in the cost of service ($276.99). For any given revenue requirement for a rate class, increasing the customer charge decreases the per therm charge. In addition, the customer charge is a small percentage of monthly bills for IS/ITS customers, who are large volume customers, compared to other rate classes, and therefore setting the customer charge at cost is reasonable.

We approved the rate design for the residential standby generator service (RS-GS) rate in Docket No. 080072-GU.[20] The level of the RS-GS customer charge and the size of the initial block of usage that includes no per therm charge (0-19.80 therms) is derived to yield the same revenue for an average residential or generator customer. The current RS-GS customer charge is based on an average residential consumption of 22.17 therms and was based on FPUC's 2004 rate case, Docket No. 040216-GU. In his testimony, FPUC witness Schneidermann stated that the monthly average residential consumption fell to 19.8 therms per month. Based on the approved residential customer charge ($11) and our per therm charge as shown below (51.792 cents per therm) a residential customer using 19.8 therms will pay $21.25 (without the cost of gas). Therefore, based on the approved rate design for the RS-GS rate, the approved RS-GS customer charge is $21.25. The rate design for the proposed new Commercial Standby Generator Service (CS-GS) rate is discussed below.

[20] See Order No. PSC-08-0643-TRF-GU, issued October 6, 2008, in Docket No. 080072-GU, In re: Petition for approval of residential standby generator rate schedule, by Florida Public Utilities Company.

D. Per Therm Non-Fuel Energy Charges

The non-fuel energy charge (energy charge) is the variable per-therm charge, and recovers FPUC's cost of providing distribution service. The energy charge does not include the actual gas commodity, as that is shown separately on the bill and determined in the annual PGA proceedings. The energy charges are calculated to recover the class revenue requirement that remains after subtracting the revenues generated by the approved customer charges.

The table below shows the energy charges that were in effect prior to the interim increase, the interim charges (effective March 12, 2009), the FPUC proposed charges, and our approved charges. All charges are shown in cents per therm.

Rate Schedule	Prior to Interim	Interim	FPUC Proposed	Commission Approved
RS	48.340	51.938	52.786	51.792
GS-1	32.107	33.668	41.265	40.000
GSTS-1	32.107	33.589	41.265	40.000
GS-2	32.107	33.668	41.265	40.000
GSTS-2	32.107	33.589	41.265	40.000
LVS	23.809	24.921	37.897	36.041
LVTS	23.809	24.883	37.897	36.041
IS	10.039	10.546	27.106	23.484
ITS	10.039	10.493	27.106	23.484
GLS/GLSTS	17.689	18.429	25.552	24.623
RS-GS	0 (0-22.17 therms) 48.340 (< 22.17 therms)	n/a	0 (0-19.80 therms) 52.786 (< 19.80 therms)	0 (0-19.80 therms) 51.792 (< 19.80 therms)
CS-GS	n/a	n/a	0 (0-39.52 therms) 41.265 (< 39.52 therms)	0 (0-39.52 therms) 40.000 (< 39.52 therms)

Schedule 7, page 1 of 6, shows a summary of the current and our approved customer and energy charges for all rate schedules. Schedule 7, pages 2 through 6, show comparisons of monthly residential and commercial bills at various consumption levels. A residential customer using 20 therms per month paid $27.02 (including May 2009 PGA and conservation costs) prior to interim rates going into effect. Under the approved RS rates, the customer would see a $3.69 increase.

E. Miscellaneous Service Charges

The miscellaneous service charges are fixed charges that are paid when a specified activity occurs. The miscellaneous service charges are designed to recover the Company's costs associated with the specific activity.

FPUC incurs higher costs to connect or reconnect a commercial customer compared to a residential customer. When connecting a customer, FPUC typically first performs a pressure test on the line to ensure that there is no gas leakage. Then, FPUC tests each gas appliance on the premises to ensure the equipment operates properly and in a safe manner. Commercial customers are served by larger lines, and the pressure test takes longer. A large commercial customer may also have more specialized equipment, adding to the time required to perform a connection or reconnection.

The Company also proposed to eliminate from its tariff the processing fee associated with accepting credit cards or debit cards for customers who choose this payment method. In its last rate case, FPUC received approval to accept credit and debit card payments for $3.50 per transaction. The charge was designed for the Company to recover its bank and overhead costs associated with processing credit card payments. However, FPUC explained that VISA and MasterCard have rules in place that do not allow the taker of a credit card, i.e., FPUC, to charge a transaction fee. Therefore, FPUC contracted with an independent third party to process optional payments by credit and debit cards. The third party's transaction fee is also $3.50. However, since the fee goes towards a third party vendor, not FPUC, the fee does not need to be in FPUC's tariff. Most electric or gas companies have contracted with an outside vendor to process payment by credit or debit card.

Based on our review of the cost support filed by FPUC for its proposed miscellaneous charges, we find that FPUC's proposed charges are reasonable, and they shall be approved as shown in the table below. The table also shows the present miscellaneous service charges and the Company-proposed charges.

Miscellaneous Service Charge	Present Miscellaneous Service Charge	Company Proposed Service Charge	Commission Approved Service Charge
Establishment of Service - Regularly Scheduled			
RS, RS-GS	$42.00	$52.00	$52.00
GS-1, GS-2, CS-GS, GSTS-1, GSTS-2	$60.00	$75.00	$75.00
LVS, LVTS, IS, ITS	$90.00	$112.00	$112.00
Establishment of Service - Same Day or Outside Normal Business Hours			
RS, RS-GS	$56.00	$69.00	$69.00
GS-1, GS-2, CS-GS, GSTS-1, GSTS-2	$79.00	$96.00	$96.00
LVS, LVTS, IS, ITS	$119.00	$144.00	$144.00
Change of Account			
Regularly Scheduled	$19.00	$23.00	$23.00
Same Day or Outside Normal Business Hours	$24.00	$29.00	$29.00
Reconnection After Disconnection for Non-Pay - Regularly Scheduled			
RS, RS-GS	$60.00	$81.00	$81.00
GS-1, GS-2, CS-GS, GSTS-1, GSTS-2	$78.00	$104.00	$104.00
LVS, LVTS, IS, ITS	$108.00	$141.00	$141.00
Reconnection After Disconnection for Non-Pay - Same Day or Outside Normal Business Hours			
RS, RS-GS	$74.00	$98.00	$98.00
GS-1, GS-2, CS-GS, GSTS-1, GSTS-2	$97.00	$125.00	$125.00
LVS, LVTS, IS, ITS	$137.00	$173.00	$173.00
Bill Collection in Lieu of Disconnection for Non-Pay			
All rate classes	$16.00	$25.00	$25.00

Miscellaneous Service Charge	Present Miscellaneous Service Charge	Company Proposed Service Charge	Commission Approved Service Charge
Trip Charge			
Regularly Scheduled	$19.00	$23.00	$23.00
Same Day or Outside Normal Business Hours	$24.00	$29.00	$29.00

F. Temporary Disconnection Charges

FPUC proposed two new miscellaneous service charges for temporary disconnection at the customers' request. This charge covers the cost of shutting off a customer's utilities when necessary to have other services performed such as termite tenting and similar situations that require the utilities to be turned off. The proposed charge for this service is $29 for regularly scheduled service performed within the Company's regular business hours, and $35 for same day service performed outside of the Company's normal business hours (this is a premium service offered at a higher charge to cover the cost of overtime paid to an employee working beyond their normal work schedule to provide this service).

Our review of the cost information submitted in schedule E-3 by the Company shows that the proposed charge for standard and premium service is cost-based and appropriate. Therefore, FPUC shall be allowed to charge the charges set out above.

G. Stratification of the Current Commercial General Service (GS/GST) Rate Class Into Two Rate Classes (GS-1/GSTS-1 and GS-2/GSTS-2)

Currently, small to medium-sized commercial customers take service under the GS rate class, which is available to customers who use 0-5,999 therms per year. Large volume customers who use more than 6,000 therms per year take service under the LVS rate. Sales customers take service under the GS class, while transportation customers take service under the GST class. Sales and transportation customers pay the same base rates.

The GS-1/GSTS-1 rate schedule will be available to commercial customers who use 0-599 therms per year, and the GS-2/GSTS-2 rate schedule will be available to commercial customers who use 600 to 5,999 therms per year. FPUC proposed a $20 customer charge for the GS-1/GSTS-1 class and a $33 customer charge for the GS-2/GSTS-2 class. Both classes will pay the same per therm rate. The lower GS-1 customer charge is intended to reduce the financial impact on the smaller commercial customers. A lower customer charge benefits small users, since the customer charge constitutes a larger component of the bill.

In addition to customer impact considerations, there is a cost basis to stratify the GS class into two classes. FPUC stated that customer costs vary between commercial customers due to the size of the meter required. The GS-2 customers are expected to have higher peak requirements due to higher sales, which would require a larger meter, regulator, and meter set piping compared to the smaller use GS-1 customers. We find that the proposed replacement of the existing GS rate class with two classes (GS-1 and GS-2) is appropriate and it is approved.

H. Residential Standby Generator Service (RS-GS)

In Docket No. 080072-GU, FPUC received approval for a new RS-GS schedule.[21] The rate is available for residential customers whose only gas appliance is a gas-fired electric generator to provide service when electric service to the customer's premises is interrupted. Prior to receiving approval for the RS-GS rate in October 2008, residential customers with generators were taking service under the residential rate. At the end of 2007, FPUC provided service to 432 generator-only residential customers under the residential rate. Since the RS-GS rate became effective in October 2008, FPUC stated that 14 new customers have requested service under that rate schedule. Generators are optional equipment and their installation costs range from $6,000 to $20,000, depending on the size of the generator.

In July 2008, FPUC provided customer notice of its proposed RS-GS rate schedule to the generator-only customers. Eighteen out of 432 customers objected to the new rate. We determined that the residential rate does not provide for the appropriate cost recovery of generator-only customers, and therefore approved the RS-GS rate for new customers effective September 16, 2008. However, in light of customer comments received, we ordered that current generator-only customers remain on the residential rate until the resolution of FPUC's next rate case, which is this docket. A bill impact analysis provided by FPUC in Docket No. 080072-GU showed that the monthly gas bill for generator-only customers would increase between $0 and $10.72, depending on usage, if they were to be transferred from the residential to the RS-GS rate.

The increase in bills for some generator-only customers is due to the rate design of the current RS-GS rate, which provides for a higher monthly customer charge ($18.72) than the residential customer charge ($8). However, the higher $18.72 customer charge includes an initial block of usage (0-22.17 therms) that has no per-therm base rate charge. Thus, a generator-only customer who uses 1 therm or 22.17 therms per month pays $18.72. Usage above 22.17 therms is billed at the residential therm charge. As discussed above, the approved RS-GS customer charge is $21.25. The cost of gas is recovered through a separate PGA factor. If the customer uses no gas during the billing period, he will not be charged for gas. The customer charge represents the minimum bill that has to be paid whether any gas is used or not. The level of customer charge and the size of the initial block were derived to yield the same revenue for an average residential or generator-only customer. That is the same rate design we approved for the Peoples Gas System's (Peoples Gas) generator-only rate schedules.[22]

Customer Education Campaign:

FPUC explained that customers occasionally contact the Company during a storm event because the generator does not start when needed for back-up power. Only after FPUC travels to

[21] See Order No. PSC-08-0643-TRF-GU, issued October 6, 2008, in Docket No. 080072-GU, In re: Petition for approval of a residential standby generator rate schedule, by Florida Public Utilities Company.
[22] See Order No. PSC-07-0530-TRF-GU, issued June 26, 2007, in Docket No. 070260-GU, In re: Petition for approval of standby generator rate schedules RS-SG and CS-SG, by Peoples Gas System.

the customer's premises does it sometimes find that the generator does not start because the customer is not running or exercising the generator for 15 minutes every week as required by the manufacturer. FPUC explained that it plans on mailing an educational bill insert to its customers who own generators about the required weekly running of the generator before this year's hurricane season starts. Under this new RS-GS rate design, FPUC believes that once the customer understands that he is already paying through the customer charge for a certain amount of usage, the customer will exercise the generator. Running the generator on a weekly basis as required by the manufacturer will ensure the safety of the generator, alleviate customer frustration during a storm event, and will free up FPUC personnel who will otherwise have to make a trip to the premises. FPUC projects that its educational program will result in increased generator usage that will most likely, on average, equal or exceed the minimum bill requirement for the RS-GS rate.

We ordered FPUC in Docket No. 080072-GU to include a generator-only rate classification as part of its cost of service study in Docket No. 080366-GU. FPUC stated that it reviewed the facilities needed to serve a generator-only customer, and concluded that they are comparable to the facilities required to serve a residential customer with other gas appliances. FPUC explained that the Company used to install 1/2 inch gas service lines and 125 cubic feet per hour (cfh) meters to serve residential customers. These installations were not large enough to deliver sufficient gas quantities to serve a full-house generator. However, FPUC stated that the Company now uses 3/4 inch service lines, and 250 cfh meters for all residential customers. These larger facilities are able to serve most residential generators. Customers who require very large generator installations are required to pay a contribution-in-aid-of-construction to cover the cost of the upgraded service line facilities.

<u>Conclusion:</u>

In a rate case all costs, rates, and charges are subject to review and change. We find that this rate case proceeding is the appropriate time to transfer all residential generator-only customers who currently take service under the residential rate to the RS-GS rate schedule approved in Docket No. 080072-GU. We further find that there is no basis to continue to allow generator-only customers to remain in the residential class, while requiring new customers to take service under the RS-GS rate. In addition, when we approved generator-only rate schedules for Peoples Gas in Docket No. 070260-GU, we approved the transfer of all residential and commercial generator-only customers who were taking service under the residential or commercial rate to Peoples Gas' new generator-only rate schedules.

<u>I. Commercial Standby Generator Service (CS-GS) Rate Schedule</u>

FPUC proposed a new commercial standby generator service (CS-GS) rate schedule for commercial customers who are using natural gas for the purpose of fueling a generator to provide electricity to the premises during power outages and whose only gas appliance is the generator. Typical commercial customers using standby generators are restaurants or hospitals. Commercial customers with a generator and other gas appliance(s) will continue to take service under the otherwise applicable commercial rate. FPUC received approval for residential standby generator rate schedule (RS-GS) in Docket No. 080072-GU.[23] We also approved residential and commercial generator rate schedules for Peoples Gas.[24]

FPUC's proposed rate structure for commercial standby generator-only customers reflects the rate design approved for the RS-GS rate and for the Peoples Gas generator rate schedules. FPUC proposed a $36.31 customer charge and an initial block of usage (0-39.52 therms) that includes no per-therm base rate charge. Based on our approved revenue increase, the appropriate customer charge is $35.81. The $35.81 charge is derived to yield the same revenue as a GS-1 customer who uses 39.52 therms per month. The customer charge represents the minimum charge that will have to paid every month. Usage above 39.52 therms is billed at the GS non-fuel energy charge. In both cases, cost of gas is recovered through a separate PGA factor. If the customer uses no gas during the billing period, he will not be charged for gas.

FPUC stated that the typical usage of a commercial generator rated at 1,900 cubic feet being exercised for 15 minutes weekly is 39.52 therms per month. FPUC stated that the proposed rate design is to encourage commercial customers to run their generators once a week as required by the manufacturer. As also discussed above, FPUC explained that customers contact the Company during a storm event when the generator does not start when needed for back-up power, which requires FPUC to travel to the site. FPUC then determines that the generator does not start because the customer is not running the generator as required by the manufacturer to ensure the generator starts when needed. In addition, FPUC explained that customers may run the generator, however, it is done so under no load. Therefore, when there is an actual power failure, and the generator will try to keep up with electrical demand, the generator may not perform in a safe and reliable manner.

FPUC explained that it plans on educating its commercial generator customers through a bill insert prior to the start of hurricane season about the required maintenance, and that the monthly customer charge provides for no per-therm charge for usage up to 39.53 therms. FPUC believes that if a customer understands that he is already paying through the customer charge for a certain amount of usage, the customer will exercise the generator as required by the manufacturer to ensure the generator starts when needed.

Under FPUC's proposal, all current generator-only customers will be transferred to the new CS-GS rate. FPUC currently serves 159 commercial generator only customers. The current generator-only customers take service under FPUC's GS rate, and pay a monthly $15 customer charge and 32.1076 cents per therm energy charge. That reflects the current GS charges, prior to any increase approved in this docket. As shown above, the approved GS-1 customer charge is $20, and the per-therm charge is 40.000 cents per therm.

Based on the above, we find that FPUC's proposed CS-GS rate is appropriate and it is approved.

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[23] See Order No. PSC-08-0643-TRF-GU, issued October 6, 2008, in Docket No. 080072-GU, In re: Petition for approval of residential standby generator rate schedule, by Florida Public Utilities Company.
[24] See Order No. PSC-07-0530-TRF-GU, issued June 26, 2007, in Docket No. 070260-GU, In re: Petition for approval of standby generator rate schedules RS-SG and CS-SG, by Peoples Gas System.

J. Gas Lighting Service Transportation Service (GLSTS) Rate Schedule

The Company previously offered transportation services for gas lights under the commercial transportation rate schedules. This new tariff separates gas lighting transportation service into its own category. This proposed tariff complies with Rule 25-7.0335(1) F.A.C., which states that gas companies must offer a transportation service option for every commercial rate plan.

This proposed tariff allows commercial gas lighting customers another option to purchase their gas from a gas marketer. The $4.50 administrative charge covers the estimated expense of having FPUC's Energy Logistics staff coordinate the reporting, nominations, and balancing of gas supplies with other parties on behalf of the transportation customers. This charge was established in FPUC's 2004 rate case, in Docket No. 040216-GU, and FPUC decided not to increase the previously approved charge.

K. Area Expansion Surcharge

Upon receiving a request to extend facilities, the Company assesses numerous conditions, such as the potential customer's credit worthiness and projected revenue generated from the extension. As provided for in Rule 25-7.054, F.A.C., the Company compares four times the expected annual revenue generated by the extension (Maximum Allowable Construction Cost or MACC) to the projected construction costs. If the construction costs are less then the MACC, the extension is provided free of cost to the customer. If the construction costs exceed the MACC, FPUC will require the customer to pay a Contribution in Aid of Construction (CIAC), also referred to as the Excess Construction Costs (ECC).

The AEP is an alternative method to collecting all ECC incurred from extending such facilities via a CIAC. The AEP allows customers to pay the CIAC over a time period of up to ten years, as opposed to collecting the total balance up-front. On or before May 1 of each year, the Company files a report with this Commission reconciling AEP facilities costs and surcharge revenues on an annual and total date. Any revenues collected by the Company in excess of the installed cost are refunded to the customers, and the AEP is terminated.

Current Tariff Overview:

We approved FPUC's AEP in 1995.[25] Currently, the recovery process is a cents-per-therm surcharge levied to customers served by AEP facilities on a monthly basis. This method has proven extremely volatile due to variables such as predicted therm usage embedded in the AEP surcharge equation. If the Company over-predicts the therm usage of any class, the Company may be unable to recapture the full ECC, placing the burden on FPUC, and ultimately other ratepayers in the next rate case. Additionally, the current program places an unfair burden on customers who use more gas than those who have very low or no gas use. A user with multiple gas appliances is impacted to a much greater extent than a customer who installs a

[25] Order PSC-95-0162-FOF-GU, issued February 7, 1995, in Docket No. 941291-GU, In re: Petition for approval of modification to tariff provisions governing main and service extensions by Florida Public Utilities Company.

standby natural gas generator that is used rarely, even though the investment to bring gas to each customer is the same.

Proposed Modifications to AEP:

The Company proposed changing the AEP surcharge from a cents-per-therm charge to a fixed monthly per premises dollar amount. This consists of a three step process. First, for a requested extension of services, the Company will calculate the AEP Recovery Amount. Then, FPUC will divide the AEP Recovery Amount by the total estimated number of therms subject to the AEP surcharge. This is the Unitized AEP Recovery Amount. Finally, to determine an individual customer's initial surcharge, the Company will multiply the Unitized AEP Recovery Amount by the projected average monthly usage by rate schedule. This value is the Initial AEP Surcharge. This is the individual customer's CIAC required for an extension of services.

Upon completion of the initial five-year period from the in-service date of the AEP facilities extension, FPUC proposed an adjustment to allow for a recalculation of the outstanding AEP Recovery Amount, using a similar method as described above. This adjustment will permit FPUC to compare the actual ECC to the originally-calculated ECC and change the fixed monthly surcharge, either up or down. It has been the Company's experience that build-out for most projects are completed in four years or less. Historically, 41 out of the total 45 AEP projects were never fully collected in our approved ten-year timeframe. Allowing the Company to reassess the surcharge at the five-year point allows for better matching of revenues and costs. We approved similar methods for a recalculated AEP Surcharge and a true-up for Chesapeake Utilities Corporation[26] and St. Joe Natural Gas.[27] We believe that this approach may prevent further lags in uncollected ECC.

The Company requested to use the maximum authorized rate of return for determination of future AEP costs. In response to our staff's Second Data Request, the Company claims its proposed approach will be conservative by raising the "hurdle" rate for approval of an AEP project, in order to ensure the successful outcome in terms of covering ECC within the ten-year allowable collection period. We are not aware of any regulated gas utilities which use the currently authorized maximum rate of return for such calculations. FPUC has not demonstrated any critical need for using the maximum authorized rate of return for calculating AEP costs. Therefore, we find that FPUC shall use the rate of return mid-point for all AEP cost estimates.

Conclusion:

Based on the above, we find that FPUC's requested changes to its AEP, with the exception of the requested rate of return to be used in AEP calculations shall be approved. FPUC shall use the mid-point of its approved rate of return for AEP calculations. The proposed methodology of collection appears much more precise in determining, monitoring, and capturing

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[26] Order PSC-07-0427-TRF-GU, issued May 15, 2007 in Docket No. 060675-GU, In Re: Order Approving in Part Petition for Authority to Implement Phase Two of Experimental Transitional Transportation Service Pilot Program and for Approval of New Tariff to Reflect Transportation Service Environment
[27] Order PSC-04-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In Re: Order Granting Rate Increase by St. Joe Natural Gas Company, Inc.

the ECC incurred by Company. The proposed AEP modifications shall become effective on the effective date discussed below, along with all other tariffs approved in this docket. FPUC requested an earlier effective date, but now agrees that the effective date shall be as discussed below.

L. Proposed Increase to All Existing Area Expansion Surcharges to Lower the Projected Unrecovered Excess Construction Cost Balances

FPUC is proposing a partial true-up of costs and revenues for existing AEP projects, by implementing an additional surcharge on customers served by the AEP projects. This surcharge represents a change in FPUC's policy, in that the original AEP contracts did not contemplate a true-up in AEP charges. However, as noted above, we approved the concept of a true-up mechanism for AEP projects for Chesapeake Gas Company and St. Joe Gas Company, in which the costs and revenues are reviewed during the 10-year period and adjusted as necessary to meet the revenue target. FPUC has also requested a true-up provision for future projects which was addressed above. Unrecovered costs from AEP projects are transferred to the applicable capital plant construction account, and ultimately to the base rates of all FPUC customers. FPUC proposed increasing the surcharges to all existing 41 AEP participants to lower the projected unrecovered excess construction costs balances. This change would only apply to any AEP facilities constructed prior to January 1, 2009. As discussed above, FPUC proposed a true-up mechanism for future AEP projects which should eliminate or significantly reduce any shortfalls for future AEP projects.

FPUC currently has 41 AEP projects with projected ECC balances totaling $3,913,429, through December 2008. If the programs are continued unaltered through their ten-year timeline, the uncollectable balance would amount to $3,081,798. The Company stated the ECC shortfall is due to unpredictable events such as market downturns, increased appliance efficiency and housing market fluctuations which altered the predictive powers for FPUC to determine therm use. FPUC proposed to transfer $2,478,621 to plant-in-service accounts. The proposed increased AEP Surcharge would recover the remaining $603,177.

The Company originally asked to increase the AEP surcharge to $0.50 per therm for all customers. It has since modified its request to differentiate the charge by prorated rate class, to comply with the current Commission approved method. The Company seeks to increase the cents-per-therm AEP Surcharge for the Residential class to $0.50 per therm, the General Service class to $0.33, the Large Volume class to $0.25 and the Gas Lighting to $0.18. FPUC chose $0.50 for the residential class as a reasonable surcharge, stating that bills would be competitive in conjunction with any other approved rate increase in this docket. The ratio among classes index the Residential class at 100 percent, the General Service class at 66.4 percent, the Large Volume Service class at 49.2 percent and the Gas Lights class at 36.6 percent. FPUC derived these surcharge values using the same method currently approved by this Commission for allocating and structuring AEP Surcharges among rate classes.

We find that the proposed AEP true-up shall be approved, and $603,177 will be assessed to the customers who enjoy the benefits of the plant expansions paid for through the AEP, and not collected through higher rates to the general body of ratepayers. Currently, the Residential

AEP Surcharge has a range of $0.10 to $0.35 per therm, depending on the particular AEP project. Pending the approval of the proposed $0.50 per therm, residential AEP customers would see an AEP Surcharge increase of $0.40 to $0.15 per therm, respectively. For an average 20 therm residential monthly bill, this is approximately a $5.00 increase.

In conclusion, the movement and division of outstanding ECC between the current AEP customers and the base rate payers appears more equitable than moving any additional costs to rate base, while not imposing an unreasonable burden on current AEP customers. This true-up will allow FPUC to close up to 19 open AEP projects and decrease the ECC on many more. Therefore, FPUC's proposed true-up to its AEP surcharge is approved, and FPUC shall implement the proposed true-up for all existing outstanding AEP customers.

M. Effective Date for FPUC's Revised Rates and Charges

All new rates and charges shall become effective for meter readings on or after 30 days from April 21, 2009. FPUC shall file revised tariffs to reflect the approved final rates and charges for administrative approval within five (5) business days of issuance of the PAA Order. Pursuant to Rule 25-22.0406(8), F.A.C., customers shall be notified of the revised rates in their first bill containing the new rates. A copy of the notice shall be submitted to our staff for approval prior to its use.

IX. INTERIM RATES

By Order No. PSC-09-0123-PCO-GU, issued March 3, 2009, we authorized the collection of interim rates, subject to refund, pursuant to Section 366.071, F.S. The approved interim revenue requirement was $27,075,841, which represents an increase of $984,054 or 4.18 percent. The interim collection period was March 2009 through May 2009.

According to Section 366.071, F.S., any refund should be calculated to reduce the rate of return of the utility during the pendency of the proceeding to the same level within the range of the newly authorized rate of return. Adjustments made in the rate case test period that do not relate to the period interim rates are in effect should be removed. Rate case expense is an example of an adjustment which is recovered only after final rates are established.

In this proceeding, the test period for establishment of interim rates is the 12-month period ending December 31, 2007. FPUC's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of actual interest costs, and the lower limit of the last authorized range for ROE.

To establish the proper refund amount, we have calculated a revised interim revenue requirement utilizing the same data used to establish final rates for the 2009 projected test year. Items, such as rate case expense and the storm damage accrual, were excluded because these items are prospective in nature and did not occur during the interim collection period. Using the principles discussed above, we find the revenue requirement for the interim collection period to be $31,740,788. Because the $27,075,841 revenue requirement, granted in Order No. PSC-09-

0123-PCO-GU, for the December 2007 interim test year is less than the revenue requirement for the interim collection period of $31,740,788, no refund is required. Further, upon issuance of the Consummating Order in this docket, the corporate undertaking shall be released.

X. ADJUSTMENTS TO ANNUAL REPORTS, RATE OF RETURN REPORTS, AND BOOKS AND RECORDS

FPUC shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of our findings in this rate case.

XI. SOUTH FLORIDA OPERATIONS CENTER

The Company's current South Florida Operations Center is located on the site of a former Manufactured Gas Plant. It will have to be relocated prior to commencing any clean up of the existing site. The relocation will have to be permanent since the current site was rezoned for usages which are inconsistent with the current use of the site.

The new South Florida Operations Center was an issue in the Company's last rate case in Docket No. 040216-GU. In that case, the Company had requested to include $2,500,000 for the purchase of land for the new center, in the projected test year 2005. In Order No. PSC-04-1110-PAA-GU, we stated:

> The utility planned to purchase land in Palm Beach County in mid-2004 for the new location of its operations center, at a cost of $2,500,000. However, the utility has now indicated that the anticipated cost of the land is $4,200,000 due to a substantial increase in demand for this type of property. The utility further indicated that the total cost would be approximately $4,500,000, including $300,000 in attorney's fees, closing costs, and other costs. The utility did not indicate that the proposed operations center would be occupied by the end of the projected test year, or that construction of the center would have even begun.
>
> . . . we find that this land shall be considered non used and useful for the purpose of setting rates in this case and the $2,500,000 shall be removed from rate base.
>
> . . . Once the new operations building is placed in service, as well as the existing center retired, the utility may seek recovery in its next rate case.

In the present rate case, the Company did not include the cost of the new South Florida Operations Center as a part of the requested rate relief. Although the Company has purchased a 6.22-acre site located in the Town of Lake Park, the operations center is not expected to be completed until October 2010, or ten months after the end of the projected 2009 test year. The Company has been negotiating with three developers/builders to act as its agent to develop and to manage the site development and construction. The Company has also entered into an agreement with an Architectural/Engineering firm. The expected design fee is $186,500. The projected cost of site development and construction has been independently estimated at $4,744,000.

Due to the large amount of expenditures for the construction of the operations center, the Company has requested that we consider granting special future rate relief. The Company estimated the revenue requirement associated with the operations center to be $909,488. The Company proposed two alternatives for consideration that would provide rate relief without the need for a "separate costly and time consuming rate proceeding."

The first alternative would be to calculate a flat percentage increase as a part of the present proceeding, that would be added to base rates based on the information that is available in the testimony, exhibits, and MFRs, in this proceeding. This rate increase would become effective upon completion of the operations center.

The Company's second proposed alternative would be for this Commission to conduct a limited proceeding at the conclusion of the operations center construction. The limited proceeding would specifically address the effects on rate base and net operating income relating to the incremental cost associated with the new operations center, and the cost of the limited proceeding.

We believe that there is a great deal of uncertainty as to the completion date and total cost of the new operations center. The current estimate calls for the completion of the center in 18 months or 10 months from the end of the 2009 projected test year. We also believe that the cost estimates for the operations center will change during the next approximate 18 months. Therefore, we find it is not appropriate to approve the Company's first alternative of granting a step rate increase now to be added to customer bills when the center is operational.

The Company's second alternative of the filing of a limited proceeding is also problematic. FPUC, or any other utility, may petition this Commission for a limited proceeding. However, there can be no guarantee now that we will agree that a limited proceeding is appropriate at the time the petition is filed. We could, among other things, determine that the issue of the overall earnings level should be addressed, based on the circumstances at the time of the proceeding. While limiting the cost of proceedings before this Commission is desirable, we see no need to take action at this time with respect to approving the use of a limited proceeding in the future.

Therefore, the step increase for the new South Florida Operations Center is denied at this time, and we will take no other action with respect to possible proceedings for this matter in the future.

XII. CONTINGENCY PROVISIONS IN EVENT PROPOSED MERGER WITH CHESAPEAKE IS CONSUMMATED

As stated earlier in this Order, FPUC and Chesapeake have announced their intention to merge with a closing expected in the fourth quarter of 2009. Such merger could make the rates we are proposing in this Order to be inappropriate. To allow for this contingency, this docket shall remain open, and in the event the merger is consummated, the following conditions shall apply:

1. a new docket will be opened;
2. the Company shall file MFRs and testimony (reflecting at a minimum, the effect of the merger, the synergies of the merger, and the change in capital structure), within 180 days from the date the merger is consummated, based on a 2011 test year; and
3. the increased revenues granted by this Order shall be held subject to refund from the date that the merger is consummated.

Based on the foregoing, it is

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

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

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

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

ORDERED that Florida Public Utilities Company is authorized to collect increased revenues of $8,496,230. It is further

ORDERED that no refund of the interim rate increase approved by Order No. PSC-09-0123-PCO-GU, issued March 3, 2009, shall be required. It is further

ORDERED that upon issuance of the Consummating Order in this docket, the corporate undertaking shall be released. It is further

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

ORDERED that the rate increase shall be effective on billings rendered for all meter readings taken on or after June 4, 2009. It is further

ATTACHMENT A

ORDERED that Florida Public Utilities Company shall file a report with the Commission's Division of Economic Regulation, within 90 days of the final order in this rate case, showing the dollar amount and feet of plastic mains and services installed in 2005, 2006, 2007, and 2008, to replace the bare steel pipe retired in those same years. It is further

ORDERED that, thereafter, Florida Public Utilities Company shall file an annual status report by March 31 of each year showing the dollar amount and feet of plastic mains, services and tubing installed during the previous calendar year to replace bare steel pipe and tubing retired that year. It is further

ORDERED that Florida Public Utilities Company shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of our findings in this rate case. It is further

ORDERED that the bad debt adjustment is for ratemaking purposes only, and that for surveillance, annual report, and other reporting purposes, Florida Public Utilities Company shall report its actual bad debt expense. It is further

ORDERED that in the event the merger with Chesapeake Utilities Corporation is consummated: a new docket will be opened; Florida Public Utilities Company shall file MFRs and testimony based on a 2011 test year within 180 days from the date the merger is consummated: and the increased revenues granted by this Order shall be held subject to refund from the date that the merger is consummated as set forth in the body of this Order. It is further

ORDERED that if no substantially affected person files a protest within 21 days of the date of the Proposed Agency Action Order, a Consummating Order shall be issued and the docket shall remain open for the review of any merger with Chesapeake Utilities Corporation, and for the filing of the appropriate notices and tariffs.

By ORDER of the Florida Public Service Commission this 27th day of May, 2009.

ANN COLE
Commission Clerk

By: Dorothy E. Menasco
Dorothy E. Menasco
Chief Deputy Commission Clerk

(S E A L)

RRJ

DISSENTS BY: CHAIRMAN CARTER AND COMMISSIONER ARGENZIANO

CHAIRMAN CARTER dissents without opinion.

COMMISSIONER ARGENZIANO dissents without opinion.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

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

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on June 17, 2009.

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

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

ATTACHMENT A

FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU
13-MONTH AVERAGE RATE BASE
DECEMBER 2009 TEST YEAR

SCHEDULE 1

Issue	Adjusted per Company	Plant in Service & Acquisition Adjustment	Accumulated Deprec., Amort. & Customer Adv.	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
		117,563,771	(39,309,022)	78,254,749	359,427	0	78,614,176	(4,866,956)	73,747,220
No.	Commission Adjustments:								
4	Updated Allocations	81,565	(79,623)	1,942	0	0	1,942	0	1,942
5	Allocation of EDP Equipment	90,819	(52,067)	38,752	0	0	38,752	0	38,752
6	Bare Steel Replacement Program	(67,503)	716	(66,787)	0	0	(66,787)	0	(66,787)
7	Area Expansion Program (AEP) defic	17,419	0	17,419	0	0	17,419	0	17,419
8	Account 252 - Customer Advances	0	(87,449)	(87,449)	0	0	(87,449)	0	(87,449)
9	Working Capital	0	0	0	0	0	0	(26,028)	(26,028)
28	Storm Damage Accrual	0	0	0	0	0	0	81,040	81,040
30	Rate Case Expense	0	0	0	0	0	0	(324,270)	(324,270)
31	Depreciation Study	0	(118,954)	(118,954)	0	0	(118,954)	0	(118,954)
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
				0			0		0
				0			0		0
				0			0		0
				0			0		0
				0			0		0
---	Total Commission Adjustments	122,300	(337,377)	(215,077)	0	0	(215,077)	(269,258)	(484,335)
10	Commission Adjusted Rate Base	117,686,071	(39,646,399)	78,039,672	359,427	0	78,399,099	(5,136,214)	73,262,885

ATTACHMENT A

FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2009 TEST YEAR

SCHEDULE 2

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	31,130,696	42.21%	11.75%	4.96%
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%
Customer Deposits	6,181,495	8.38%	6.13%	0.51%
Deferred Income Taxes	2,773,818	3.76%	0.00%	0.00%
Tax Credits - Zero Cost	0	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	115,553	0.16%	9.38%	0.01%
Total	73,747,219	100.00%		8.74%
Equity Ratio	48.13%			

Commission Adjusted	($) Amount	($) Specific Adjustments	($) Pro Rata Adjustments	($) Commission Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	31,130,696	0	(233,125)	30,897,571	42.17%	10.85%	4.58%
Long-term Debt	25,861,386	0	(193,665)	25,667,721	35.04%	7.90%	2.77%
Short-term Debt	7,363,771	0	(55,144)	7,308,627	9.98%	2.73%	0.27%
Preferred Stock	320,500	0	(2,400)	318,100	0.43%	4.75%	0.02%
Customer Deposits	6,181,495	0	0	6,181,495	8.44%	6.13%	0.52%
Deferred Income Taxes	2,773,818	0	0	2,773,818	3.79%	0.00%	0.00%
Tax Credits - Zero Cost	0	0	0	0	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	115,553	0	0	115,553	0.16%	8.72%	0.01%
Total	73,747,219	0	(484,335)	73,262,884	100.00%		8.17%
Equity Ratio	48.13%			48.13%			

Interest Synchronization	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Dollar Amount Change					
Long-term Debt	(193,665)	7.90%	(15,300)	38.575%	5,902
Short-term Debt	(55,144)	2.73%	(1,505)	38.575%	581
Customer Deposits	0	6.13%	0	38.575%	0
					6,483
Cost Rate Change					
Short-term Debt	7,363,771	-1.98%	(145,803)	38.575%	56,243
Tax Credits - Weighted Cost	115,553	-0.66%	(768)	38.575%	296
					56,539
TOTAL					63,022

FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU
NET OPERATING INCOME
DECEMBER 2009 TEST YEAR

SCHEDULE 3

		Operating Revenues	O&M Gas Cost	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	27,918,917	0	19,003,804	4,499,008	5,609,864	(1,529,681)	0	27,582,995	335,922
	Commission Adjustments:									
4	Updated Allocations	0	0	0	17,740	0	(6,676)	0	11,064	(11,064)
5	Allocation of EDP Equipment	0	0	0	9,616	0	(3,619)	0	5,997	(5,997)
6	Bare Steel Replacement Program	0	0	0	122,780	0	(46,202)	0	76,578	(76,578)
18	Non-Regulated Business Operations	0	0	(73,751)	0	0	27,753	0	(45,998)	45,998
19	Franchise Fees	(1,441,002)	0	0	0	(1,441,002)	0	0	(1,441,002)	0
20	Gross Receipts Tax	(2,315,886)	0	0	0	(2,315,886)	0	0	(2,315,886)	0
21	Trending	0	0	0	0	0	0	0	0	0
22	Customer Records and Collections	0	0	24,539	0	0	(9,234)	0	15,305	(15,305)
23	Uncollectible Accounts Expense	0	0	(116,853)	0	0	43,972	0	(72,881)	72,881
24	Travel Expense	0	0	(2,093)	0	0	788	0	(1,305)	1,305
25	Promotional Advertising	0	0	(56,238)	0	0	21,162	0	(35,076)	35,076
26	Administrative and General Expense	0	0	(44,595)	0	0	16,781	0	(27,814)	27,814
27	Corporate Office Flooring	0	0	(6,750)	0	0	2,540	0	(4,210)	4,210
28	Storm Damage Accrual	0	0	(162,080)	0	0	60,991	0	(101,089)	101,089
29	Employee Benefits	0	0	(235,805)	0	0	88,733	0	(147,072)	147,072
30	Rate Case Expense	0	0	(60,109)	0	0	22,619	0	(37,490)	37,490
31	Depreciation Study	0	0	0	205,596	0	(77,366)	0	128,230	(128,230)
32	Vacant Positions	0	0	(190,505)	0	0	71,687	0	(118,818)	118,818
33	South Florida Operations Center	0	0	0	0	(114,079)	42,928	0	(71,151)	71,151
34	Common Plant Allocations	0	0	0	0	(66,363)	24,972	0	(41,391)	41,391
35	Income Tax Expense	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	63,022	0	63,022	(63,022)
	Total Commission Adjustments	(3,756,888)	0	(924,240)	355,732	(3,937,330)	344,852	0	(4,160,986)	404,098
36	Commission Adjusted NOI	24,162,029	0	18,079,564	4,854,740	1,672,534	(1,184,829)	0	23,422,009	740,020

ATTACHMENT A

SCHEDULE 4

FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU
DECEMBER 2009 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) Commission Adjusted
1	Revenue Requirement	100.0000	100.0000
2	Gross Receipts Tax	0.0000	0.0000
3	Regulatory Assessment Fee	(0.5000)	(0.5000)
4	Bad Debt Rate	(0.7300)	(0.5100)
5	Net Before Income Taxes	98.7700	98.9900
6	Income Taxes (Line 5 x 37.63%)	(37.1672)	(37.2499)
7	Revenue Expansion Factor	61.6028	61.7400
8	Net Operating Income Multiplier (100%/Line 7)	1.6233	1.6197

SCHEDULE 5

FLORIDA PUBLIC UTILITIES COMPANY
DOCKET NO. 080366-GU
DECEMBER 2009 PROJECTED TEST YEAR
REVENUE REQUIREMENTS CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$73,747,220	$73,262,885
2.	Overall Rate of Return	8.74%	8.17%
3.	Required Net Operating Income (1)x(2)	6,445,507	5,985,578
4.	Achieved Net Operating Income	335,922	740,020
5.	Net Operating Income Deficiency (3)-(4)	6,109,585	5,245,558
6.	Net Operating Income Multiplier	1.62330	1.61970
7.	Operating Revenue Increase (5)x(6)	$9,917,690	$8,496,230

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 1 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

SCHEDULE A
CALCULATION OF FINAL RATES

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

SPLIT GS CHARGES

	TOTAL	RS	GS/GSTS	LV/LVTS	IS/ITS	GLS/GLSTS
APPROVED TOTAL TARGET REVENUES	36,415,147	15,222,302	7,056,364	12,658,629	1,352,259	125,592
LESS:OTHER OPERATING REVENUE & TAXES	5,919,233	3,174,598	1,080,195	1,476,273	171,247	16,920
LESS:CUSTOMER CHARGE REVENUES						
FINAL CUSTOMER CHARGES		11.00	29.08	90.00	280.00	0.00
TIMES:NUMBER OF BILLS	52,137	47,235	3,565	1,282	13	42
EQUALS:CUSTOMER CHARGE REVENUES	8,907,523	6,234,982	1,243,993	1,384,869	43,680	0
LESS:OTHER NON-THERM-RATE REVENUES						
EQUALS:PER-THERM TARGET REVENUES	21,588,391	5,812,722	4,732,176	9,797,488	1,137,333	108,672
DIVIDED BY:NUMBER OF THERMS	55,522,630	11,223,250	11,830,427	27,184,610	4,842,992	441,352
EQUALS:PER-THERM RATES(UNRNDED)		0.517917868	0.400000437	0.360405691	0.234840903	0.246226233
PER-THERM RATES(RNDED)		0.51792	0.40000	0.36041	0.23484	0.24623
PER-THERM-RATE REVENUES(RNDED RATES	21,588,524	5,812,746	4,732,171	9,797,605	1,137,328	108,674

	RS	GS-1&2 / GSTS-1&2	LV/LVTS	IS/ITS	GLS/GLSTS
SUMMARY: APPROVED TARIFF RATES					
CUSTOMER CHARGES	11.00	29.08	90.00	280.00	-
ENERGY CHARGES					
NON-GAS (DOLLARS PER THERM)	0.51792	0.40000	0.36041	0.23484	0.24623
PURCHASED GAS ADJUSTMENT	0.70000	0.70000	0.70000	0.70000	0.70000
TOTAL (INCLUDING PGA)	1.21792	1.10000	1.06041	0.93484	0.94623
SUMMARY:PRESENT TARIFF RATES					
CUSTOMER CHARGES	8.00	15.00	45.00	240.00	0.00
ENERGY CHARGES					
NON-GAS (DOLLARS PER THERM)	0.48340	0.32107	0.23809	0.10039	0.17689
PURCHASED GAS ADJUSTMENT	0.70000	0.70000	0.70000	0.70000	0.70000
TOTAL (INCLUDING PGA)	1.18340	1.02107	0.93809	0.80039	0.71769

Notes:

Transportation Service accounts are responsible for for additional charges due to the extra services which are provided by FPU.

The **Pool Manager Service** charge remains at $100.00 per month per Pool Manager.

The **GS** rate is approved to be replaced by a **GS-1** and **GS-2** rate. The Customer Charges are approved at $20 / customer per month for GS-1 and the GS-2 monthly Customer Charge per customer is approved to be 163% above the GS-1 proposed Customer Charge based on the index ratios between GS-2 and GS-1 on Schedule E-7.

As such the GS-2 approved Customer Charge is $33.00 per customer per month.

To demonstrate the overall effect on GS customers the weighted average projected GS-1 and GS-2 Customer Charge of $29.08 / customer per month is used on this schedule.

The weighted average projected composite GS Customer Customer Charge is based on 1,074 GS-1 customers at $20.00 and 2,491 GS-2 Customers at $33.00.

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 8 - PAGE 2 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

SCHEDULE A
OTHER OPERATING REVENUES
CURRENT CHARGES

ACCT	OTHER REVENUES	PROJECTED 2009* REVENUE @ CURRENT CHARGES	ACTUAL 2007 REVENUE @ CURRENT CHARGES	CURRENT SERVICE CHARGES 2007 REVENUES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS	*	CURRENT SERVICE CHARGES RATES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS	*	CURRENT SERVICE CHARGES ALLOCATE TOTAL REVENUE BY CUSTOMER OR SPECIFIC 2007 NUMBER OF OCCURANCES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS	TOTAL
487	FORFEITED DISCOUNTS	902,300	779,563	706,265	53,303	19,173	194	628	*	N/A	N/A	N/A	N/A	N/A	*	47,235	3,565	1,282	13	42	52,137
4880	MISC SERVICE REV-OTHER CHARGE	33,230	58,394	52,959	3,997	1,436	-	-	*	42.00	60.00	90.00			*	1,261	67	18			1,344
4880									*						*						
4881	MISC SERVICE REV-CREDIT		2,044	2,044						3.50	3.50	3.50	3.50	3.50		584	-	-			584
4882	MISC SERVICE REV-CHECK CHARGE	28,889	31,891	28,711	2,187	779	8	26	*	N/A	N/A	N/A	N/A	N/A	*	47,235	3,565	1,282	13	42	52,137
4884	MISC SVC REV-CHANGE OF ACCOUNT	29,188	37,066	33,581	2,534	912	9	30	*	19.00	19.00	19.00	19.00	19.00	*	47,235	3,565	1,282	13	42	52,137
4884									*	24.00	24.00	24.00	24.00	24.00	*						
4885	MISC SVC REV-RECONNECT CHARGE	249,730	270,292	245,137	18,501	8,655	-	-	*	21.00	21.00	48.00			*	11,873	681	139			12,693
4886	MISC SVC REV-RECONNECT NON-PAY	289,953	287,899	261,105	19,706	7,086	-	-	*	60.00	78.00	108.00			*	4,352	253	66			4,670
4886			-				-		*	74.00	97.00	137.00	137.00		*	-	-	-			-
4887	MISC SVC REV-BILL COLLECT CHG	93,576	76,112	66,956	5,204	1,872	19	61	*	18.00	16.00	16.00	16.00	16.00	*	4,310	325	117			4,752
	LAKE WORTH	698,427	706,870	268,022	125,399	264,863	48,418	3,103	*	16.00	16.00	18.00	16.00	18.00	*	-	-	-			-
4888	MISC SVC REV-ALLOWANCES & ADJ	(13,600)	(13,255)	(12,009)	(906)	(326)	(3)	(11)	*						*	47,235	3,565	1,282	13	42	52,137
4952	MISC.GAS REVENUE	44,992	43,079	39,029	2,946	1,060	11	35	*						*	47,235	3,565	1,282	13	42	52,137
4953	UNBILLED REVENUES	(38,596)							*						*	47,235	3,565	1,282	13	42	52,137
49561	OTHER GAS REV - STORM	-	183,828	148,424	11,202	4,029	41	132		N/A	N/A	N/A	N/A	N/A		47,235	3,565	1,282	13	42	52,137
498	RATE REFUND PENDING ACCOUNTS	-	30,301	27,452	2,072	745	8	24	*	N/A	N/A	N/A	N/A	N/A	*	47,235	3,565	1,282	13	42	52,137
	2007 REVENUES @ CURRENT CHARGES		2,474,618	1,889,675	246,123	306,087	46,704	4,028													
	2009 REVENUES @ CURRENT CHARGES	2,315,886	ALLOCATE	1,749,747	230,336	288,325	43,706	3,770	*						*	n/a	n/a	n/a	n/a	n/a	n/a

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 3 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

SCHEDULE A
OTHER OPERATING REVENUES
PROPOSED CHARGES

PROJECTED TEST YEAR: 12/31/2009

ACCT	OTHER REVENUES	REVENUE @ PROPOSED CHARGES	2009 REVENUES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS
487	FORFEITED DISCOUNTS	902,300	817,462	61,895	22,192	225	727
4880	MISC SERVICE REV-OTHER CHARGE	41,100	37,275	2,813	1,012	-	-
4880							
4882	MISC SERVICE REV-CHECK CHARGE	28,700	26,001	1,962	706	7	23
4884	MISC SVC REV-CHANGE OF ACCOUNT	35,300	31,981	2,414	868	9	28
4884		-	-	-	-	-	-
4885	MISC SVC REV-RECONNECT CHARGE	309,200	280,423	21,164	7,613	-	-
4886	MISC SVC REV-RECONNECT NON-PAY	391,400	354,973	26,790	9,636	-	-
4886							
4867	MISC SVC REV-BILL COLLECT CHG	146,200	132,454	9,996	3,596	36	116
	LAKE WORTH	696,427	263,317	123,197	260,017	45,603	3,048
4866	MISC SVC REV-ALLOWANCES & ADJ	(13,600)	(12,321)	(930)	(334)	(3)	(11)
493	RENT FROM GAS PROPERTY	-					
4951	OVER REC;FUEL ADJ- PURCHAS GAS	-					
4952	MISC.GAS REVENUE	44,992	40,761	3,076	1,107	11	36
4953	UNBILLED REVENUES	(38,598)	(34,969)	(2,639)	(949)	(10)	(31)
	SERVICE CHARGE & INCREMENTAL REVENUES	2,543,421	1,937,358	249,539	305,462	45,879	3,939
	TOTAL GROSS RECEIPTS REVENUES	1,936,054	596,864	438,509	784,332	125,368	12,981
	TOTAL FRANCHISE FEE REVENUES	1,441,002	640,377	394,147	406,478	-	-
	TOTAL OTHER REVENUES	5,920,477	3,174,598	1,060,195	1,476,273	171,247	16,920
	PROPOSED INCREASE IN OTHER REVENUES	226,291	187,811	19,204	17,137	2,170	169

ACCT	OTHER REVENUES	2009 RATES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS	ALLOCATE TOTAL REVENUE BY CUSTOMER OR SPECIFIC 2009 NUMBER OF OCCURANCES RS	GS	LV/LVTS	IS/ITS	GLS/GLSTS	TOTAL
487	FORFEITED DISCOUNTS	NO CHANGE IN RATE - ALLOCATED BASED ON CUSTOME					47,235	3,565	1,282	13	42	52,137
4880	MISC SERVICE REV-OTHER CHARGE	52.00	75.00	112.00			717	38	9			763
4880							597	24	6	-	-	627
4882	MISC SERVICE REV-CHECK CHARGE	NO CHANGE IN RATE - ALLOCATED BASED ON CUSTOME					47,235	3,565	1,282	13	42	52,137
4884	MISC SVC REV-CHANGE OF ACCOUNT	23.00	23.00	23.00	23.00	23.00	1,390	105	38			1,533
4884							-	-	-	-	-	-
4885	MISC SVC REV-RECONNECT CHARGE	52.00	75.00	112.00	-	-	5,393	282	68			5,743
4886	MISC SVC REV-RECONNECT NON-PAY	81.00	104.00	141.00	-	-	4,382	258	68			4,708
4886												
4867	MISC SVC REV-BILL COLLECT CHG	25.00	25.00	25.00	25.00	25.00	47,235	3,565	1,282	13	42	52,137
	LAKE WORTH						-	-	-	-	-	-
4866	MISC SVC REV-ALLOWANCES & ADJ	NO CHANGE IN RATE - ALLOCATED BASED ON CUSTOME					47,235	3,565	1,282	13	42	52,137
493	RENT FROM GAS PROPERTY						47,235	3,565	1,282	13	42	52,137
4951	OVER REC;FUEL ADJ- PURCHAS GAS						47,235	3,565	1,282	13	42	52,137
4952	MISC.GAS REVENUE						47,235	3,565	1,282	13	42	52,137
4953	UNBILLED REVENUES						47,235	3,565	1,282	13	42	52,137
	SERVICE CHARGE & INCREMENTAL REVENUES						n/a	n/a	n/a	n/a	n/a	n/a

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 4 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

SCHEDULE A
CALCULATION OF FINAL RATES

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

	TOTAL	RS	GS-1&2 / GSTS-1&2	LV/LVTS	IS/ITS	GLS/GLSTS
PROPOSED TOTAL TARGET REVENUES	**36,415,147**	**15,222,302**	**7,056,364**	**12,858,629**	**1,352,259**	**125,592**
LESS:OTHER OPERATING REVENUE & TAXES	5,919,233	3,174,598	1,080,195	1,476,273	171,247	16,920
LESS:CUSTOMER CHARGE REVENUES						
PROPOSED CUSTOMER CHARGES		11.00	29.08	90.00	280.00	-
TIMES:NUMBER OF BILLS	52,137	47,235	3,565	1,282	13	42
EQUALS:CUSTOMER CHARGE REVENUES	8,907,523	6,234,982	1,243,993	1,384,869	43,680	-
LESS:OTHER NON-THERM-RATE REVENUES						
EQUALS:PER-THERM TARGET REVENUES	21,588,391	5,812,722	4,732,176	9,797,488	1,137,333	108,672
DIVIDED BY:NUMBER OF THERMS	55,522,630	11,223,250	11,830,427	27,184,610	4,842,992	441,352
EQUALS:PER-THERM RATES(UNROUNDED)		0.51791767	0.40000044	0.36040569	0.23484090	0.24622623
PER-THERM RATES(ROUNDED)		0.51792	0.40000	0.36041	0.23484	0.24623
PER-THERM-RATE REVENUES (ROUNDED RATES)		5,812,746	4,732,171	9,797,605	1,137,328	108,674
SUMMARY:PROPOSED TARIFF RATES						
CUSTOMER CHARGES		11.00	29.08	90.00	280.00	-
ENERGY CHARGES						
NON-GAS (DOLLARS PER THERM)		0.51792	0.40000	0.36041	0.23484	0.24623
PURCHASED GAS ADJUSTMENT (April 09)		0.70000	0.70000	0.70000	0.70000	0.70000
TOTAL (INCLUDING PGA)		1.21792	1.10000	1.06041	0.93484	0.94623
SUMMARY:PRESENT TARIFF RATES						
CUSTOMER CHARGES		8.00	15.00	45.00	240.00	-
ENERGY CHARGES						
NON-GAS (DOLLARS PER THERM)		0.48340	0.32107	0.23809	0.10039	0.01769
PURCHASED GAS ADJUSTMENT		0.70000	0.70000	0.70000	0.70000	0.70000
TOTAL (INCLUDING PGA)		1.18340	1.02107	0.93809	n/a	0.71769

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 5 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

SCHEDULE B
FINAL RATE DESIGN

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009
WITNESS: SCHNEIDERMANN

	TOTAL	RS	GS-1&2 / GSTS-1&2	LV/LVTS	IS/ITS	GLS/GLSTS		
TOTAL CURRENT BASE REVENUES	22,225,975	9,967,462	4,448,135	7,201,038	531,262	78,078	-	
TOTAL PROPOSED BASE REVENUES		12,047,704	5,976,168	11,182,357	1,181,013	108,672	-	
CURRENT OTHER OPERATING REV	2,312,116	1,749,747	230,336	288,325	43,708			
PROPOSED OTHER OPERATING REV	2,542,177	1,937,358	249,539	305,462	45,879	3,939	-	-
INCREASE OTHER OPERATING REV	226,291	187,611	19,204	17,137	2,170	169	-	-
GR TAX REVENUES	1,936,054	596,864	436,509	764,332	125,368	12,981		
FF REVENUES	1,441,002	640,377	394,147	406,478	-	-		
TOTAL CURRENT REVENUES	27,915,147	12,954,449	5,509,127	8,660,174	700,339	91,059	-	-
TOTAL PROPOSED REVENUES	36,415,147	15,222,302	7,056,364	12,658,629	1,352,259	125,592		-

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 6 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

FINAL RATE DESIGN
SCHEDULE B

	TOTAL	RS	GS-1&2 / GSTS-1&2	LV/LVTS	IS/ITS	GLS/GLSTS
I. PRESENT RATES (projected test year @ present rates)						
Gas Sales (due to growth)	22,225,975	9,967,462	4,448,135	7,201,038	531,262	78,078
Other Operating Revenue	2,315,886	1,749,747	230,336	288,325	43,708	3,770
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981
Total	27,918,917	12,954,449	5,509,127	8,660,174	700,339	94,828
ATTENDANT INCREASE IN TAXES	(1,184,829)	(419,249)	(243,862)	(457,851)	(58,111)	(5,756)
RESULTING NET OPERATING INCOME	740,020	1,088,253	338,435	(526,084)	(170,668)	10,083
RATE OF RETURN	1.01%	4.20%	2.24%	-1.86%	-4.75%	2.83%
INDEX		4.16	2.22	-1.84	-4.70	2.80
II. REVENUES IF SET AT EQUAL RATES OF RETURN (projected test year @ approved rates - equal rates of return)						
Gas Sales (due to growth)	30,495,914	11,447,704	5,876,168	11,782,357	1,281,013	108,672
Other Operating Revenue	2,542,177	1,937,358	249,539	305,462	45,879	3,939
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981
Total	36,415,147	14,622,302	6,956,364	13,258,629	1,452,259	125,592
TOTAL REVENUE INCREASE	8,496,230	1,667,853	1,447,237	4,598,455	751,921	30,764
PERCENT INCREASE OVER BASE RATES	38.23%	16.73%	32.54%	63.86%	141.53%	39.40%
RATE OF RETURN	8.17%	8.17%	8.17%	8.17%	8.17%	8.17%
INDEX		0.41	0.41	0.41	0.41	0.41
III. FINAL REVENUES (projected test year @ approved rates - ADJUSTED)						
Gas Sales (due to growth)	30,495,914	12,047,704	5,976,168	11,182,357	1,181,013	108,672
Other Operating Revenue	2,542,177	1,937,358	249,539	305,462	45,879	3,939
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981
Total	**36,415,147**	**15,222,302**	**7,056,364**	**12,658,629**	**1,352,259**	**125,592**
TOTAL REVENUE INCREASE	8,496,230	2,267,853	1,547,237	3,998,455	651,921	30,764
PERCENT INCREASE OVER BASE RATES	38.23%	22.75%	34.78%	55.53%	122.71%	39.40%
RATE OF RETURN	8.17%	9.60%	8.58%	6.86%	6.45%	8.17%
INDEX		1.17	1.05	0.84	0.79	1.00

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 7 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

RATE OF RETURN BY CUSTOMER CLASS
SCHEDULE C

	TOTAL	RS	GS / GSTS	LV/LVTS	IS/ITS	GLS/GLSTS			
REVENUES (projected test year @ proposed rates - equal rates of return)									
Gas Sales (due to growth)	30,495,914	11,447,704	5,876,168	11,782,357	1,281,013	108,672	-	-	
Other Operating Revenue (proposed rates)	2,542,177	1,937,358	249,539	305,462	45,879	3,939	-	-	
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981	-	-	
Total	36,415,147	14,622,302	6,956,364	13,258,629	1,452,259	125,592	-	-	
EXPENSES:									
Purchased Gas Cost	-	-	-	-	-	-	-	-	
O&M Expenses	18,079,564	8,359,816	3,351,802	5,837,780	483,599	46,568	-	-	
Depreciation Expenses	3,622,061	1,307,415	740,648	1,384,589	172,355	17,054	-	-	
Amortization Expenses	1,232,679	444,946	252,061	471,211	58,657	5,804	-	-	
Taxes Other Than Income--Fixed	1,912,771	690,431	391,128	731,186	91,019	9,006	-	-	
Taxes Other Than Income--Revenue	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-	
Total Expses excl. Income Taxes	28,363,726	12,285,444	5,414,555	9,644,109	929,117	90,501	-	-	
PRE TAX NOI:	8,051,421	2,336,858	1,541,809	3,614,520	523,142	35,092	-	-	
ATTENDANT INCREASE IN TAXES	3,250,672	638,124	553,715	1,759,377	287,686	11,770	-	-	
INCOME TAXES:	2,065,843	218,875	309,853	1,301,526	229,575	6,015	-	-	
NET OPERATING INCOME:	5,985,578	2,117,983	1,231,957	2,312,994	293,567	29,077	-	-	-
RATE BASE:	73,262,887	25,923,909	15,079,027	28,310,824	3,593,226	355,901	-	-	
RATE OF RETURN	8.17%	8.17%	8.17%	8.17%	8.17%	8.17%			
$ CHANGE IN BASE REVENUES	8,269,939	1,480,242	1,428,033	4,581,318	749,751	30,595			
% CHANGE IN BASE REVENUES	37.21%	14.85%	32.10%	63.62%	141.13%	39.19%			
FINAL REVENUES (projected test year @ approved rates - adjusted for LV and IS)									
Gas Sales (due to growth)	30,495,914	12,047,704	5,976,168	11,182,357	1,181,013	108,672	-	-	
Other Operating Revenue (proposed rates)	2,542,177	1,937,358	249,539	305,462	45,879	3,939		-	
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981	-	-	
Total	36,415,147	15,222,302	7,056,364	12,658,629	1,352,259	125,592	-	-	
EXPENSES:									
Purchased Gas Cost	-	-	-	-	-	-	-	-	
O&M Expenses	18,079,564	8,359,816	3,351,802	5,837,780	483,599	46,568	-	-	
Depreciation Expenses	3,622,061	1,307,415	740,648	1,384,589	172,355	17,054	-	-	
Amortization Expenses	1,232,679	444,946	252,061	471,211	58,657	5,804	-	-	
Taxes Other Than Income--Fixed	1,912,771	690,431	391,128	731,186	91,019	9,006	-	-	
Taxes Other Than Income--Revenue	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-	
Total Expses excl. Income Taxes	28,363,726	12,285,444	5,414,555	9,644,109	929,117	90,501	-	-	
PRE TAX NOI:	8,051,421	2,936,858	1,641,809	3,014,520	423,142	35,092	-	-	
INCREASE NOI:	5,245,558	1,400,169	955,261	2,468,639	402,495	18,994			
ORIGINAL NOI:	740,020	1,088,253	338,435	(526,084)	(170,668)	10,083			
INCOME TAXES:	2,065,843	448,436	348,113	1,071,965	191,315	6,015			
NET OPERATING INCOME:	5,985,578	2,488,422	1,293,696	1,942,555	231,827	29,077			
RATE BASE:	73,262,887	25,923,909	15,079,027	28,310,824	3,593,226	355,901			
RATE OF RETURN	8.17%	9.60%	8.58%	6.86%	6.45%	8.17%			
$ CHANGE IN BASE REVENUES	8,269,939	2,080,242	1,528,033	3,981,318	649,751	30,595			
% CHANGE IN BASE REVENUES	37.21%	20.87%	34.35%	55.29%	122.30%	39.19%			

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 8 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

RATE OF RETURN BY CUSTOMER CLASS
SCHEDULE C

	TOTAL	RS	GS / GSTS	LV/LVTS	IS/ITS	GLS/GLSTS		
PRESENT RATES (projected test year @ present rates)								
Gas Sales (Projected Test Year Therms)	22,225,975	9,967,462	4,448,135	7,201,038	531,262	78,078		-
Other Operating Revenue (Current Charges)	2,315,886	1,749,747	230,336	288,325	43,708	3,770		
Gross Recp + FF Tax	3,377,056	1,237,240	830,656	1,170,810	125,368	12,981		
Total	27,918,917	12,954,449	5,509,127	8,660,174	700,339	94,828	-	-
EXPENSES:								
Purchased Gas Cost	-	-	-	-	-	-	-	
O&M Expenses	18,079,564	8,359,816	3,351,802	5,837,780	483,599	46,568	-	-
Depreciation Expenses	3,622,061	1,307,415	740,646	1,384,589	172,355	17,054	-	-
Amortization Expenses	1,232,679	444,946	252,061	471,211	58,657	5,804	-	-
Taxes Other Than Income--Fixed	1,912,771	690,431	391,128	731,186	91,019	9,006	-	-
Taxes Other Than Income--Revenue	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-
Total Expses excl. Income Taxes	28,363,726	12,285,444	5,414,555	9,644,109	929,117	90,501	-	-
INCOME TAXES:	(1,184,829)	(419,249)	(243,862)	(457,851)	(58,111)	(5,756)	-	-
NET OPERATING INCOME:	740,020	1,088,253	338,435	(526,084)	(170,668)	10,083	-	-
RATE BASE:	73,262,887	25,923,909	15,079,027	28,310,824	3,593,226	355,901		
REALIZED RATE OF RETURN	1.01%	4.20%	2.24%	-1.86%	-4.75%	2.83%		
REQUIRED RATE OF RETURN	8.17%	8.17%	8.17%	8.17%	8.17%	8.17%		
REQUIRED NET OPERATING INCOME	5,985,578	2,117,983	1,231,957	2,312,994	293,567	29,077		
NOI DEFICIENCY	5,245,558	1,029,730	893,521	2,839,078	464,235	18,994		
Net Operating Income Multiplier	1.6197	1.6197	1.6197	1.6197	1.6197	1.6197		
Revenue Deficiency (Excess)	8,496,230	1,667,853	1,447,237	4,598,455	751,921	30,764		
Proposed Increase in Other Operating Revenues	226,291	187,611	19,204	17,137	2,170	169		
Required Increase in Base Revenues	8,269,939	1,480,242	1,428,033	4,581,318	749,751	30,595		
Increase in Revenue Taxes (GR, FF)								

ATTACHMENT A

SCHEDULE H-1 | COST OF SERVICE | SCHEDULE 6 - PAGE 9 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

DERIVATION OF REVENUE DEFICIENCY
SCHEDULE D

	TOTAL	RS	GS / GSTS	LV/LVTS	IS/ITS	GLS/GLSTS		
CUSTOMER COSTS	16,717,267	9,628,248	2,784,536	4,257,973	43,168	3,342	-	-
CAPACITY COSTS	11,832,412	2,651,117	2,705,211	5,484,271	902,131	89,681	-	-
COMMODITY COSTS	1,098,146	221,977	233,986	537,667	95,786	8,729	-	-
REVENUE COSTS	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-
TOTAL	33,164,475	13,984,179	6,402,649	11,499,253	1,164,573	113,822	-	-
less:REVENUE AT PRESENT RATES (in the projected test year)	27,918,917	12,954,449	5,509,127	8,660,174	700,339	94,828	-	-
equals: NOI DEFICIENCY	5,245,558	1,029,730	893,521	2,839,078	464,235	18,994	-	-
UNIT COSTS:								
CUSTOMER COSTS	26.72	16.99	65.09	276.72	276.72	6.63		
CAPACITY (CENTS/THERM)	1.9378	18.6012	18.7705	19.8245	21.0856	19.7404		
COMMODITY (CENTS/THERM)	0.0198	0.1978	0.1978	0.1978	0.1978	0.1978		

ATTACHMENT A

SCHEDULE H-1

COST OF SERVICE

SCHEDULE 6 - PAGE 10 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY SUMMARY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

SUMMARY	TOTAL	RS	GS / GSTS	LV/LVTS	IS/ITS	GLS/GLSTS			
RB	73,262,887	25,923,909	15,079,027	28,310,824	3,593,226	355,901	-	-	-
ATTRITION	-	-	-	-	-	-	-	-	-
O&M	18,079,564	8,359,816	3,351,802	5,837,780	483,599	46,568	-	-	-
DEPRECIATION	3,622,061	1,307,415	740,648	1,384,589	172,355	17,054	-	-	-
AMORTIZATION EXPENSES	1,232,679	444,946	252,061	471,211	58,657	5,804	-	-	-
TOTI - OTHER	1,912,771	690,431	391,128	731,186	91,019	9,006	-	-	-
TOTI - REV. RELATED	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-	-
INCOME TAXES TOTAL	(1,184,829)	(419,249)	(243,862)	(457,851)	(58,111)	(5,756)	-	-	-
REVENUE CREDITED TO COS:	-	-	-	-	-	-	-	-	-
TOTAL COST - CUSTOMER	16,717,267	9,628,248	2,784,536	4,257,973	43,168	3,342	-	-	-
TOTAL COST - CAPACITY	11,832,412	2,651,117	2,705,211	5,484,271	902,131	89,681	-	-	-
TOTAL COST - COMMODITY	1,098,146	221,977	233,986	537,667	95,786	8,729	-	-	-
TOTAL COST - REVENUE	3,516,651	1,482,836	678,916	1,219,343	123,487	12,069	-	-	-
NO. OF CUSTOMERS	52,137	47,235	3,565	1,282	13	42	-	-	-
PEAK MONTH SALES	6,106,118	1,425,239	1,441,202	2,766,404	427,842	45,430	-	-	-
ANNUAL SALES	55,522,630	11,223,250	11,830,427	27,184,610	4,842,992	441,352	-	-	-

ATTACHMENT A

SCHEDULE H-2 | COST OF SERVICE | SCHEDULE 6 - PAGE 11 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY
SUMMARY

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

SUMMARY	TOTAL	RS	GS / GSTS		LV/LVTS	IS/ITS	GLS/GLSTS
RB	73,262,887	25,923,909	15,079,027	-	28,310,824	3,593,226	355,901
ATTRITION							
O&M	18,079,564	8,359,816	3,351,802	-	5,837,780	483,599	46,568
DEPRECIATION	3,622,061	1,307,415	740,648	-	1,384,589	172,355	17,054
AMORTIZATION EXPENSES	1,232,679	444,946	252,061	-	471,211	58,657	5,804
TOTI - OTHER	1,912,771	690,431	391,128	-	731,186	91,019	9,006
TOTI - REV. RELATED	3,516,651	1,482,836	678,916	-	1,219,343	123,487	12,069
INCOME TAXES TOTAL	(1,184,829)	(419,249)	(243,862)	-	(457,851)	(58,111)	(5,756)
REVENUE CREDITED TO COS:	-	-	-	-	-	-	-
TOTAL COST - CUSTOMER	16,717,267	9,628,248	2,784,536	-	4,257,973	43,168	3,342
TOTAL COST - CAPACITY	11,832,412	2,651,117	2,705,211	-	5,484,271	902,131	89,681
TOTAL COST - COMMODITY	1,098,146	221,977	233,986	-	537,667	95,786	8,729
TOTAL COST - REVENUE	3,516,651	1,482,836	678,916	-	1,219,343	123,487	12,069
NO. OF CUSTOMERS	52,137	47,235	3,565	-	1,282	13	42
PEAK MONTH SALES	6,106,118	1,425,239	1,441,202		2,766,404	427,842	45,430
ANNUAL SALES	55,522,630	11,223,250	11,830,427	-	27,184,610	4,842,992	441,352

SCHEDULE H-2 | COST OF SERVICE | SCHEDULE 6 - PAGE 12 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

ALLOCATION OF COST OF SERVICE TO CUSTOMER CLASSES
SCHEDULE E

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

	TOTAL	RS	GS / GSTS		LV/LVTS	IS/ITS	GLS/GLSTS	ALLOCATOR
TAXES OTHER THAN INCOME TAXES:								
Customer	744,164	428,599	123,953	-	189,542	1,922	149	WEIGHTED CUST
Capacity	1,168,607	261,833	267,175	-	541,644	89,097	8,857	CAPACITY
Subtotal	1,912,771	690,431	391,128	-	731,186	91,019	9,006	
Revenue	3,516,651	1,482,836	678,916	-	1,219,343	123,487	12,069	TAX ALLOC W/O LK WORTH
Total	5,429,422	2,173,267	1,070,044	-	1,950,529	214,506	21,075	
RETURN (NOI)								
Customer	2,206,117	1,270,605	367,465	-	561,909	5,697	441	RB-CUST-DIRECT
Capacity	3,805,432	852,628	870,025	-	1,763,801	290,135	28,842	RB-CAP-DIRECT
Commodity	(25,972)	(5,250)	(5,534)	-	(12,716)	(2,265)	(206)	RB-COM-DIRECT
Total	5,985,578	2,117,983	1,231,957	-	2,312,994	293,567	29,077	
INCOME TAXES								
Customer	(436,695)	(251,513)	(72,739)	-	(111,228)	(1,128)	(87)	RB-CUST-DIRECT
Capacity	(753,275)	(168,775)	(172,219)	-	(349,140)	(57,431)	(5,709)	RB-CAP-DIRECT
Commodity	5,141	1,039	1,095	-	2,517	448	41	RB-COM-DIRECT
Total	(1,184,829)	(419,249)	(243,862)	-	(457,851)	(58,111)	(5,756)	
REVENUE CREDITED TO COS:								
Customer	-	-	-	-	-	-	-	DIRECT
TOTAL COST OF SERVICE:								
Customer	16,717,267	9,628,248	2,784,536	-	4,257,973	43,168	3,342	
Capacity	11,832,412	2,651,117	2,705,211	-	5,484,271	902,131	89,681	
Commodity	1,098,146	221,977	233,986	-	537,667	95,786	8,729	
Subtotal	29,647,824	12,501,343	5,723,733	-	10,279,910	1,041,086	101,753	
Revenue	3,516,651	1,482,836	678,916	-	1,219,343	123,487	12,069	
Total	33,164,475	13,984,179	6,402,649	-	11,499,253	1,164,573	113,822	
Total Calculated	33,164,475	13,984,179	6,402,649	-	11,499,253	1,164,573	113,822	

ATTACHMENT A

SCHEDULE H-2

COST OF SERVICE

SCHEDULE 6 - PAGE 13 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

ALLOCATION OF COST OF SERVICE
TO CUSTOMER CLASSES
SCHEDULE E

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

	TOTAL	RS	GS / GSTS		LV/LVTS	IS/ITS	GLS/GLSTS	ALLOCATOR
OPERATIONS AND MAINTENANCE EXPENSE:								
DIRECT AND SPECIAL ASSIGNMENTS:								
CUSTOMER								
878 Meters and House Regulators	1,702,587	980,598	283,594	-	433,657	4,396	340	WEIGHTED CUST
893 Maint. of Meters & House Reg.	135,247	77,895	22,528	-	34,448	349	27	WEIGHTED CUST
874 Mains & Services	479,493	276,162	79,868	-	122,129	1,238	96	WEIGHTED CUST
892 Maint. of Services	193,322	111,343	32,201	-	49,240	499	39	WEIGHTED CUST
ALL OTHER CUSTOMER	9,804,293	5,646,746	1,633,066	-	2,497,203	25,317	1,960	
CUSTOMER TOTAL	12,314,941	7,092,745	2,051,256	-	3,136,678	31,800	2,462	
CAPACITY								
876 Measuring & Reg. Sta. Eq.- I	14,342	3,213	3,279	-	6,647	1,093	109	PEAK/AVE
890 Maint. of Meas.& Reg.Sta.Eq.-I	-	-	-	-	-	-	-	PEAK/AVE
874 Mains and Services	1,136,711	254,686	259,883	-	526,861	86,666	8,615	DIRECT
887 Maint. of Mains	436,890	97,888	99,885	-	202,497	33,310	3,311	DIRECT
ALL OTHER CAPACITY	3,057,704	685,095	699,074	-	1,417,232	233,127	23,175	PEAK/AVE
CAPACITY TOTAL	4,645,647	1,040,883	1,062,121	-	2,153,237	354,195	35,211	
COMMODITY								
Account #	-	-	-	-	-	-	-	COMMODITY
Account #	-	-	-	-	-	-	-	COMMODITY
Account #	-	-	-	-	-	-	-	COMMODITY
All Other	1,118,976	226,188	238,425	-	547,865	97,603	8,895	COMMODITY
COMMODITY TOTAL	1,118,976	226,186	238,425	-	547,865	97,603	8,895	
TOTAL O&M	18,079,564	8,359,816	3,351,802	-	5,837,780	483,599	46,568	
DEPRECIATION EXPENSE:								
Customer	1,409,164	811,603	234,720	-	358,921	3,639	282	WEIGHTED CUST
Capacity	2,212,897	495,812	505,928	-	1,025,668	168,717	16,772	DIRECT
Total	3,622,061	1,307,415	740,648	-	1,384,589	172,355	17,054	
4050.1 AMORT. OF OTHER GAS PLANT:								
Customer	177,542	102,255	29,573	-	45,221	458	35	WEIGHTED CUST
Capacity	278,806	62,468	63,743	-	129,225	21,257	2,113	PEAK/AVE
Total	456,348	164,723	93,315	-	174,446	21,715	2,149	
4060.1 AMORT. OF ACQUISITION ADJ AND BARE STEEL								
Customer	302,989	174,505	50,466	-	77,173	782	61	WEIGHTED CUST
Capacity	475,802	106,606	108,781	-	220,532	36,276	3,606	PEAK/AVE
Total	778,791	281,111	159,249	-	297,705	37,059	3,667	
4070.5 AMORT OF AEP - EXCESS MACC								
Customer	(957)	(551)	(159)	-	(244)	(2)	(0)	WEIGHTED CUST
Capacity	(1,503)	(337)	(344)	-	(697)	(115)	(11)	PEAK/AVE
Total	(2,460)	(888)	(503)	-	(940)	(117)	(12)	

ATTACHMENT A

SCHEDULE H-2	COST OF SERVICE	SCHEDULE 6 - PAGE 14 OF 21
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY	TYPE OF DATA SHOWN:
COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION		PROJECTED TEST YEAR: 12/31/2009
DOCKET NO.: 080366-GU	ALLOCATION OF RATE BASE TO CUSTOMER CLASSES SCHEDULE F	

RATE BASE BY CUSTOMER CLASS	TOTAL	RS	GS / GSTS		LV/LVTS	IS/ITS	GLS/GLSTS		ALLOCATOR
DIRECT AND SPECIAL ASSIGNMENTS:									
Customer									
Meters	6,082,886	3,503,416	1,013,205	-	1,549,342	15,707	1,216		WEIGHTED CUST
House Regulators	1,993,427	1,148,107	332,038	-	507,736	5,148	399		WEIGHTED CUST
Services	14,084,865	8,112,126	2,346,066	-	3,587,487	36,370	2,816		WEIGHTED CUST
All Other	4,841,480	2,786,432	806,428	-	1,233,149	12,502	968		WEIGHTED CUST
Total	27,002,658	15,552,081	4,497,737	-	6,877,714	69,727	5,399		
Capacity									
Industrial Meas.& Reg. Sta. Eq.	33,874	7,590	7,745	-	15,700	2,583	257		PEAK/AVE
Meas.&Reg.Sta.Eq.-Gen.	209,588	46,959	47,918	-	97,143	15,979	1,589		PEAK/AVE
Mains	39,463,891	8,842,103	9,022,518	-	18,291,340	3,008,821	299,108		PEAK/AVE
All Other	6,870,766	1,539,433	1,570,844	-	3,184,570	523,844	52,076		PEAK/AVE
Total	46,578,118	10,436,085	10,649,024	-	21,588,753	3,551,227	353,029		
Commodity									
Account	-	-	-	-	-	-	-		ANNUAL SALES
Account	-	-	-	-	-	-	-		ANNUAL SALES
Account	-	-	-	-	-	-	-		ANNUAL SALES
All Other	(317,889)	(64,258)	(67,734)	-	(155,643)	(27,728)	(2,527)		ANNUAL SALES
Total	(317,889)	(64,258)	(67,734)	-	(155,643)	(27,728)	(2,527)		ANNUAL SALES
TOTAL	73,262,887	25,923,909	15,079,027	-	28,310,824	3,593,226	355,901	#	

ATTACHMENT A

SCHEDULE H-2 | COST OF SERVICE | SCHEDULE 6 - PAGE 15 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED
EMBEDDED COST OF SERVICE STUDY

DEVELOPMENT OF ALLOCATION FACTORS
SCHEDULE G

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

	TOTAL	RS	GS / GSTS		LV/LVTS	IS/ITS	GLS/GLSTS
CUSTOMER COSTS							
CUSTOMER	52,137	47,235	3,565		1,282	13	42
AVERAGE METER COST INDEX	NA	1.00000	3.83199		16.29041	16.29041	0.39039
WEIGHTED CUSTOMER COST	82,012	47,235	13,661	-	20,889	212	16
WEIGHTED CUST	1.00	0.58	0.17	-	0.25	0.00	0.00
CAPACITY COSTS							
PEAK AND AVERAGE METHOD (THERMS)	5,443,583	1,219,665	1,244,551		2,523,077	415,032	41,258
CAPACITY	1.00	0.22	0.23	-	0.46	0.08	0.01
COMMODITY COSTS							
ANNUAL SALES (THERMS)	55,522,630	11,223,250	11,830,427		27,184,610	4,842,992	441,352
SALES	1.00	0.20	0.21	-	0.49	0.09	0.01
REVENUE-RELATED COSTS	0.01625	=FACTOR					
TAX ON CAP, CUST, COMM	481,777	203,147	93,011	-	167,049	16,918	1,653
TAX ALLOC		0.42	0.19	-	0.35	0.04	0.00
TAX ALLOC W/O LK WORTH		0.42	0.19	-	0.35	0.04	0.00

ATTACHMENT A

SCHEDULE H-2 | COST OF SERVICE | SCHEDULE 6 - PAGE 16 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY SUMMARY

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

SUMMARY:	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE
ATTRITION	-	-	-	-	-
O&M	18,079,564	12,314,941	4,645,647	1,118,976	-
DEP.	3,622,061	1,409,164	2,212,897	-	-
AMORTIZATION-OTHER GAS PLANT	456,348	177,542	278,806	-	-
AMORT OF UTILY PLANT-ACQ ADJ **AND BARE STEEL**	778,791	302,989	475,802	-	-
AMORT OF AEP - EXCESS MACC	(2,460)	(957)	(1,503)	-	-
TOTAL TAXES OTHER THAN INCOME	5,429,422	744,164	1,168,607	-	3,516,651
RETURN	5,985,578	2,206,117	3,805,432	(25,972)	-
INCOME TAXES	(1,184,829)	(436,695)	(753,275)	5,141	-
REVENUES CREDITED TO COST OF SERVICE	-	-	-	-	-
TOTAL COST	33,164,475	16,717,267	11,832,412	1,098,146	3,516,651
RATE BASE	73,262,887	27,002,658	46,578,118	(317,889)	-
KNOWN DIRECT & SPECICAL ASSIGNMENTS:					
RATE BASE ITEMS(PLANT-ACC.DEP):					
381-382 METERS	6,082,886	6,082,886	-	-	-
383-384 HOUSE REGULATORS	1,993,427	1,993,427	-	-	-
385 INDUSTRIAL MEAS.& REG.EQ.	33,874	-	33,874	-	-
376 MAINS	39,463,891	-	39,463,891	-	-
380 SERVICES	14,084,865	14,084,865	-	-	-
378 MEAS.& REG.STA.EQ.-GEN.	209,588	-	209,588	-	-
892 Maint. of Services O & M ITEMS	193,322	193,322	-	-	-
876 MEAS.& REG.STA.EQ.IND.	14,342	-	14,342	-	-
878 METER & HOUSE REG.	1,702,587	1,702,587	-	-	-
890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	-	-	-	-	-
893 MAINT.OF METERS AND HOUSE REG.	135,247	135,247	-	-	-
874 MAINS AND SERVICES	1,616,205	479,493	1,136,711	-	-
887 MAINT. OF MAINS	436,890	-	436,890	-	-

ATTACHMENT A

SCHEDULE H-3 | COST OF SERVICE | SCHEDULE 6 - PAGE 17 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

(SUMMARY)

SUMMARY:	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE
ATTRITION					
O&M	18,079,564	12,314,941	4,645,647	1,118,976	-
DEP.	3,622,061	1,409,164	2,212,897	-	-
AMORTIZATION-OTHER GAS PLANT	456,348	177,542	278,806	-	-
AMORT OF UTILY PLANT-ACQ ADJ AND BARE STEEL	778,791	302,989	475,802	-	-
AMORT OF AEP - EXCESS MACC	(2,460)	(957)	(1,503)	-	-
TOTAL TAXES OTHER THAN INCOME	5,429,422	744,164	1,168,607	-	3,516,651
RETURN	5,985,578	2,206,117	3,805,432	(25,972)	-
INCOME TAXES	(1,184,829)	(436,695)	(753,275)	5,141	-
REVENUES CREDITED TO COST OF SERVICE	1,912,771	-	-	-	-
TOTAL COST	35,077,246	16,717,267	11,832,412	1,098,146	3,516,651
RATE BASE	73,262,888	27,002,658	46,578,118	(317,889)	-
KNOWN DIRECT & SPECICAL ASSIGNMENTS:					
RATE BASE ITEMS(PLANT-ACC.DEP):					
381-382 METERS	6,082,886	6,082,886	-	-	-
383-384 HOUSE REGULATORS	1,993,427	1,993,427	-	-	-
385 INDUSTRIAL MEAS.& REG.EQ.	33,874	-	33,874	-	-
376 MAINS	39,463,891	-	39,463,891	-	-
380 SERVICES	14,084,865	14,084,865	-	-	-
378 MEAS.& REG.STA.EQ.-GEN.	209,588	-	209,588	-	-
892 Maint. of Services O & M ITEMS	193,322	193,322	-	-	-
876 MEAS.& REG.STA.EQ.IND.	14,342	-	14,342	-	-
878 METER & HOUSE REG.	1,702,587	1,702,587	-	-	-
890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	-	-	-	-	-
893 MAINT.OF METERS AND HOUSE REG.	135,247	135,247	-	-	-
874 MAINS AND SERVICES	1,616,205	479,493	1,136,711	-	-
887 MAINT. OF MAINS	436,890	-	436,890	-	-

ATTACHMENT A

SCHEDULE H-3 | COST OF SERVICE | SCHEDULE 6 - PAGE 18 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: PROVIDE A FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

TYPE OF DATA SHOWN:

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

PROJECTED TEST YEAR: 12/31/2009

CLASSIFICATION OF EXPENSES AND
DERIVATION OF COST OF SERVICE BY COST CLASSIFICATION

4010	OPERATION EXPENSES	TOTAL	CUSTOMER	CAPACITY	COMMODITY	CLASSIFIER
.	PRODUCTION EXPENSES	-	-	-	-	CAPACITY
800-812	GAS SUPPLY EXPENSE - OPERATION	-	-	-	-	COMMODITY
813	OTHER GAS SUPPLY EXPENSE	193,935	-	-	193,935	COMMODITY
814-826	STORAGE & PROCESSING - UNDERGROUND STORA(	-	-	-	-	CAPACITY
	DISTRIBUTION EXPENSES					
870	OPER SUPERVISION & ENGINEERING	420,978	266,231	154,747	-	ac 871-879
8711	DISTRIBUTION LOAD DISPATCHING	13,513	-	13,513	-	CAPACITY
874	MAINS & SERVICES EXPENSE	1,616,205	479,493	1,136,711	-	ac376*+ac380*
8751	MEAS/REGULATING STN EXP-GENERL	-	-	-	-	CAPACITY
8754	M&R STN-SCADA MNT-REPLACE PTS	-	-	-	-	CAPACITY
8761	MEAS/REGULATING STN EXP-INDUSL	14,342	-	14,342	-	CAPACITY
8771	MEAS/REG STN EXP-CITY GATE CK	20,208	-	20,208	-	CAPACITY
878	METER & HOUSE REGULATOR EXP	1,702,587	1,702,587	-	-	CUSTOMER
8791	CUSTOMER SERVICE EXP-NO CHG WK	264,872	99,098	165,774	-	ac 374-385
8792	CUSTOMER SERVICE EXP-WARRANTY	56,043	20,968	35,075	-	ac 374-385
8793	CUST SERV EXP-CHG NO PARTS NEC	(116,307)	(43,514)	(72,792)	-	ac 374-385
8801	OTHER EXPENSES MAPS & RECORDS	132,755	49,668	83,087	-	ac 374-385
8802	OTHER EXPENSES MISCELLANEOUS	867,275	324,478	542,796	-	ac 374-385
881	RENTS	58,447	-	58,447	-	CAPACITY
	CUSTOMER ACCOUNTS EXPENSES					
901	SUPERVISION	153,892	153,892	-	-	CUSTOMER
9011	SUPERVISION - A & G	70,811	70,811	-	-	CUSTOMER
902	METER READING EXPENSES	777,063	777,063	-	-	CUSTOMER
903	CUSTOMER RECORDS & COLLECTION	1,084,272	1,084,272	-	-	CUSTOMER
9031	CUST RECORDS/CLLCTN	515,794	515,794	-	-	CUSTOMER
904	UNCOLLECTIBLE ACCOUNTS	522,322	-	-	522,322	COMMODITY
905	MISC CUSTOMER ACCOUNTS EXP	98,938	98,938	-	-	CUSTOMER
9051	MISC CUST ACCNT EXP	32,760	32,760	-	-	CUSTOMER
9061-910	CUSTOMER SERVICE & INFO		-	-	-	CUSTOMER
	SUM('[Schedule_E_Final.XLS]6b'!$K$76:$K$80)					
911-916	SALES EXPENSES	1,772,317	1,772,317	-	-	CUSTOMER
920-931	ADMINISTRATIVE & GENERAL EXPENSES	6,506,834	4,432,147	1,671,968	402,719	O&M excl. A&G
4020	MAINTENANCE EXPENSES					
	DISTRIBUTION EXPENSES					
885	MAINTNCE SUPERVI & ENGINEERING	119,082	40,795	78,287	-	ac886-894
886	MAINTNCE STRUCTURE & IMPROVEMT	123,081	-	123,081	-	CAPACITY
887	MAINTENANCE OF MAINS	436,890	-	436,890	-	CAPACITY
889	MAINT OF MEAS & REG STN-GENERL	17,530	-	17,530	-	CAPACITY
890	MAINT OF MEAS & REG STN-INDUSL	-	-	-	-	CAPACITY
891	MAINT-MEAS & REG STN-CTY GS CK	54,203	-	54,203	-	CAPACITY
892	MAINTENANCE OF SERVICES	193,322	193,322	-	-	CUSTOMER
8931	MAINTENANCE OF METERS	123,543	123,543	-	-	CUSTOMER
8932	MAINTENANCE OF HOUSE REGULATOR	11,704	11,704	-	-	CUSTOMER
894	MAINTENANCE OF OTHER EQUIPMENT	12,721	4,759	7,961	-	ac 374-385
	ADMINISTRATIVE & GENERAL EXPENSES					
935	MAINTENANCE OF GENERAL PLANT	207,635	103,817	103,817	-	CAP/CUST

ATTACHMENT A

SCHEDULE H-3	COST OF SERVICE	SCHEDULE 6 - PAGE 19 OF 21
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: PROVIDE A FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY	TYPE OF DATA SHOWN:
COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	CLASSIFICATION OF EXPENSES AND DERIVATION OF COST OF SERVICE BY COST CLASSIFICATION SCHEDULE H	PROJECTED TEST YEAR: 12/31/2009

		TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE	CLASSIFIER
	DEPRECIATION AND AMORTIZATION EXPENSE:						
4030.1 & .2	DEPRECIATION EXPENSES	3,622,061	1,409,164	2,212,897	-	-	NET PLANT
4050.1	AMORTIZATION-OTHER GAS PLANT	456,348	177,542	278,806	-	-	NET PLANT
4060.1	AMORT OF UTILY PLANT-ACQ ADJ	31,056	12,082	18,974	-	-	NET PLANT
4070.3	BARE STEEL REPLACEMENT PROGRAM	747,735	290,907	456,828	-	-	NET PLANT
4070.5	AMORT OF AEP - EXCESS MACC	(2,460)	(957)	(1,503)	-	-	NET PLANT
	TAXES OTHER THAN INCOME TAXES:						
4080.1	AD VALOREM TAXES	1,276,454	496,605	779,849	-	-	NET PLANT
4080.2 & .3	GROSS RECEIPTS & FPSC ASSESSMENT	2,075,649	-	-	-	2,075,649	REVENUE
4080.4	EMERGENCY EXCISE TAX	(1,083)	(421)	(662)	-	-	NET PLANT
4080.5	FEDERAL UNEMPLOYMENT TAX	7,930	3,085	4,845	-	-	NET PLANT
4080.6	STATE UNEMPLOYMENT TAX	2,763	1,075	1,688	-	-	NET PLANT
4080.7	F.I.C.A.	619,958	241,195	378,763	-	-	NET PLANT
4080.8	MISCELLANEOUS TAXES	6,749	2,626	4,123	-	-	NET PLANT
4080.11	FRANCHISE TAX	1,441,002	-	-	-	1,441,002	REVENUE
4080.12	ENVIRONMENTAL TAX	-	-	-	-	-	NET PLANT
	REV.CRDT TO COS(NEG.OF OTHR OPR.REV)	1,912,771					
	RETURN (REQUIRED NOI)	8.17% -	2,206,117	3,805,432	(25,972)	-	RATEBASE
	INCOME TAXES						
4090.1	INCOME TAX - FEDERAL	(1,150,166)	(423,919)	(731,237)	4,991	-	RATEBASE
4090.2	INCOME TAX - STATE	-	-	-	-	-	RATEBASE
4100.1	DEFERRED INCOME TAX - FEDERAL	-	-	-	-	-	RATEBASE
4100.2	DEFERRED INCOME TAX - STATE	-	-	-	-	-	RATEBASE
4110.4	INVESTMENT TAX CREDIT	(34,663)	(12,776)	(22,038)	150	-	RATEBASE
	TOTAL O&M	18,079,564	12,314,941	4,645,647	1,118,976	-	
	TOTAL DEPRECIATION & AMORTIZATION	4,854,740	1,888,739	2,966,001	-	-	
	TOTAL TOTI	5,429,422	744,164	1,168,607	-	3,516,651	
	TOTAL NOI & REV CREDIT	5,985,578	2,206,117	3,805,432	(25,972)	-	
	TOTAL INCOME TAXES	(1,184,829)	(436,695)	(753,275)	5,141	-	
	TOTAL OPERATING EXPENSES	33,164,475	16,717,267	11,832,412	1,098,146	3,516,651	

ATTACHMENT A

SCHEDULE H-3 | COST OF SERVICE | SCHEDULE 6 - PAGE 20 OF 21

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED NATURAL GAS DIVISION
DOCKET NO.: 080366-GU

EXPLANATION: PROVIDE A FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY

CLASSIFICATION OF RATE BASE
PLANT - 1010
SCHEDULE I

TYPE OF DATA SHOWN:

PROJECTED TEST YEAR: 12/31/2009

ACCOUNT	DESCRIPTION	TOTAL	CUSTOMER	CAPACITY	COMMODITY	REVENUE	CLASSIFIER
360-363	LOCAL STORAGE PLANT	-	-	-	-		CAPACITY
301-303	INTANGIBLE PLANT:	213,641	-	213,641	-		CAPACITY
304-320	PRODUCTION PLANT	-	-	-	-		CAPACITY
	DISTRIBUTION PLANT:						
374	LAND	92,008	-	92,008	-		CAPACITY
3741	LAND RIGHTS	12,910	-	12,910	-		CAPACITY
375	STRUCTURES AND IMPROVEMENTS	384,157	-	384,157	-		CAPACITY
3761	MAINS- PLASTIC	29,730,689	-	29,730,689	-		CAPACITY
3762	MAINS -OTHER-(CAST IRON,STEEL)	30,539,600	-	30,539,600	-		CAPACITY
378	MEASURE/REGULATOR EQP.-GENERAL	307,102	-	307,102	-		CAPACITY
379	MEASURE/REG.-EQP.CITY GATE STN	2,274,266	-	2,274,266	-		CAPACITY
3801	SERVICES- PLASTIC	23,310,492	23,310,492	-	-		CUSTOMER
3802	SERVICES -OTHER- CAST IRON,ETC	2,113,030	2,113,030	-	-		CUSTOMER
380299	SERVICES CONTRA ACCOUNT	-	-	-	-		CUSTOMER
381	METERS	5,996,955	5,996,955	-	-		CUSTOMER
382	METER INSTALLATIONS	3,331,001	3,331,001	-	-		CUSTOMER
383	HOUSE REGULATORS	2,130,059	2,130,059	-	-		CUSTOMER
384	HOUSE REGULATOR INSTALLATIONS	1,000,365	1,000,365	-	-		CUSTOMER
385	IND MEASURING/REG STATION EQP	29,222	-	29,222	-		CAPACITY
386	OTHER PROPTY.ON CUST.PREM-RENT	-	-	-	-		ac 374-385
387	OTHER EQUIPMENT	754,146	282,153	471,993	-		ac 374-385
	TOTAL DISTRIBUTION PLANT	102,006,002	38,164,055	63,841,947	-		CHECKSUM
389-399	GENERAL PLANT:	10,487,364	5,243,682	5,243,682	-		CAP/CUST
1140	PLANT ACQUISITIONS:	1,263,776	-	1,263,776	-		CAPACITY
1050	GAS PLANT FOR FUTURE USE:	-	-	-	-		CAPACITY
1070	CWIP:	359,427	134,474	224,953	-		ac 374-387
	COMMON PLANT ALLOCATED						
303	MISC INTANGIBLE PLANT	953	-	953	-		CAPACITY
389	LAND	238,209	119,105	119,105	-		CAP/CUST
390	STRUCTURES AND IMPROVEMENTS	1,308,971	654,486	654,486	-		CAP/CUST
3911	OFFICE FURNITURE & EQUIPMENT	28,388	14,194	14,194	-		CAP/CUST
3912	OFFICE MACHINES	80,019	40,010	40,010	-		CAP/CUST
3913	EDP EQUIPMENT	687,901	343,951	343,951	-		CAP/CUST
391305	COMPUTER SOFTWARE	1,123,128	561,564	561,564	-		CAP/CUST
3921	TRANSPORTATION EQUIP-CARS	83,230	41,615	41,615	-		CAP/CUST
3922	TRANS-LIGHT TRUCK,VAN,	90,734	45,367	45,367	-		CAP/CUST
397	COMMUNICATION EQUIPMENT	114,406	57,203	57,203	-		CAP/CUST
398	MISCELLANEOUS EQUIPMENT	(17,218)	(8,609)	(8,609)	-		CAP/CUST
399	TANGIBLE PROPERTY	(23,432)	(11,716)	(11,716)	-		CAP/CUST
1180	TOTAL COMMON PLANT ALLOCATED	3,715,289	1,857,168	1,858,121	-		
	TOTAL PLANT	118,045,499	45,399,379	72,646,119	-		

ATTACHMENT A

SCHEDULE H-3	COST OF SERVICE	SCHEDULE 8 - PAGE 21 OF 21
FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: PROVIDE A FULLY ALLOCATED EMBEDDED COST OF SERVICE STUDY	TYPE OF DATA SHOWN:
COMPANY: FLORIDA PUBLIC UTILITIES COMPANY CONSOLIDATED NATURAL GAS DIVISION DOCKET NO.: 080366-GU	CLASSIFICATION OF RATE BASE **ACCUMULATED DEPRECIATION - 1080**	PROJECTED TEST YEAR: 12/31/2009

ACCOUNT	DESCRIPTION	TOTAL	CUSTOMER	CAPACITY	COMMODITY		CLASSIFIER
360-363	LOCAL STORAGE PLANT	-	-	-	-		CAPACITY
301-303	INTANGIBLE PLANT:	(114,332)	-	(114,332)	-		CAPACITY
304-320	PRODUCTION PLANT	-	-	-	-		CAPACITY
	DISTRIBUTION PLANT:						
374	LAND	646	-	646	-		CAPACITY
3741	LAND RIGHTS	3,241	-	3,241	-		CAPACITY
375	STRUCTURES AND IMPROVEMENTS	(190,019)	-	(190,019)	-		CAPACITY
3761	MAINS- PLASTIC	(5,546,331)	-	(5,546,331)	-		CAPACITY
3762	MAINS -OTHER-(CAST IRON,STEEL)	(15,260,067)	-	(15,260,067)	-		CAPACITY
378	MEASURE/REGULATOR EQP.-GENERAL	(97,514)	-	(97,514)	-		CAPACITY
379	MEASURE/REG.-EQP.CITY GATE STN	(546,848)	-	(546,848)	-		CAPACITY
3801	SERVICES- PLASTIC	(6,230,859)	(6,230,859)	-	-		CUSTOMER
3802	SERVICES -OTHER- CAST IRON,ETC	(1,862,728)	(1,862,728)	-	-		CUSTOMER
380299	SERVICES CONTRA ACCOUNT	-	-	-	-		CUSTOMER
381	METERS	(2,375,969)	(2,375,969)	-	-		CUSTOMER
382	METER INSTALLATIONS	(869,101)	(869,101)	-	-		CUSTOMER
383	HOUSE REGULATORS	(826,432)	(826,432)	-	-		CUSTOMER
384	HOUSE REGULATOR INSTALLATIONS	(310,565)	(310,565)	-	-		CUSTOMER
385	IND MEASURING/REG STATION EQP	4,652	-	4,652	-		CAPACITY
386	OTHER PROPTY.ON CUST.PREM-RENT	-	-	-	-		ac 374-385
387	OTHER EQUIPMENT	(128,819)	(47,118)	(81,701)	-		ac 374-385
	TOTAL DISTRIBUTION PLANT	(34,236,713)	(12,522,772)	(21,713,941)	-		CHECKSUM
389-399	GENERAL PLANT:	(1,551,149)	(775,575)	(775,575)	-		CAP/CUST
1150	ACCUM. AMORT. - ACQ. ADJ.	(544,545)	-	(544,545)	-		CAPACITY
	ACCUM. DEPR. - LEASEHOLD IMPR.	-	-	-	-		CAPACITY
2520	CUSTOMER ADV. FOR CONST.	(1,746,825)	(873,413)	(873,413)	-		CAP/CUST
1080	RETIREMENT WORK IN PROGRESS	-	-	-	-		ac 374-387
	COMMON PLANT ALLOCATED						
303	MISC INTANGIBLE PLANT	-	-	-	-		CAPACITY
389	LAND	-	-	-	-		CAP/CUST
390	STRUCTURES AND IMPROVEMENTS	(296,450)	(148,225)	(148,225)	-		CAP/CUST
3911	OFFICE FURNITURE & EQUIPMENT	(8,066)	(4,033)	(4,033)	-		CAP/CUST
3912	OFFICE MACHINES	(22,919)	(11,459)	(11,459)	-		CAP/CUST
3913	EDP EQUIPMENT	(160,361)	(80,180)	(80,180)	-		CAP/CUST
391305	COMPUTER SOFTWARE	(898,506)	(449,253)	(449,253)	-		CAP/CUST
3921	TRANSPORTATION EQUIP-CARS	(39,375)	(19,687)	(19,687)	-		CAP/CUST
3922	TRANS-LIGHT TRUCK,VAN,	(231,417)	(115,708)	(115,708)	-		CAP/CUST
397	COMMUNICATION EQUIPMENT	195,771	97,885	97,885	-		CAP/CUST
398	MISCELLANEOUS EQUIPMENT	1,644	822	822	-		CAP/CUST
399	TANGIBLE PROPERTY	6,846	3,423	3,423	-		CAP/CUST
1190	TOTAL COMMON PLANT ALLOCATED	(1,452,834)	(726,417)	(726,417)	-	-	
	TOTAL DEPRECIATION	(39,646,398)	(14,898,176)	(24,748,222)	-		
	NET PLANT	78,399,101	30,501,203	47,897,898	-		
	plus:WORKING CAPITAL	(5,136,214)	(3,498,545)	(1,319,779)	(317,889)	-	O&M EXPENSE
	TOTAL RATE BASE	**73,262,888**	**27,002,658**	**46,578,118**	**(317,889)**		

ATTACHMENT A

SCHEDULE 7
Page 1 of 6

FLORIDA PUBLIC UTILITIES COMPANY
PRESENT AND COMMISSION APPROVED RATES
DOCKET NO. 080366-GU

RATE CODE	RATE SCHEDULE	PRESENT RATE	COMMISSION APPROVED RATE
RS	RESIDENTIAL		
	CUSTOMER CHARGE	$8	$11
	ENERGY CHARGE (cents/therm)	48.340	51.792
RS-GS	RESIDENTIAL STANDBY GENERATOR SERVICE		
	CUSTOMER CHARGE	$18.72	$21.25
	ENERGY CHARGE over 19.80 therms (cents/therm)	48.340	51.792
GS-1/GSTS-1	GENERAL SERVICE 1		
	CUSTOMER CHARGE	$15	$20
	ENERGY CHARGE (cents/therm)	32.107	40.000
GS-2/GSTS-2	GENERAL SERVICE 2		
	CUSTOMER CHARGE	$15	$33
	ENERGY CHARGE (cents/therm)	32.107	40.000
CS-GS	COMMERCIAL STANDBY GENERATOR SERVICE		
	CUSTOMER CHARGE	n/a	$35.81
	ENERGY CHARGE over 39.53 therms (cents/therm)	n/a	40.000
LVS/LVTS	LARGE VOLUME		
	CUSTOMER CHARGE	$45	$90
	ENERGY CHARGE (cents/therm)	23.809	36.041
GLS/GLST	GAS LIGHTING		
	CUSTOMER CHARGE	n/a	n/a
	ENERGY CHARGE (cents/therm)	17.689	24.623
IS/ITS	INTERRUPTIBLE		
	CUSTOMER CHARGE	$240	$280
	ENERGY CHARGE (cents/therm)	10.039	23.484

ATTACHMENT A

SCHEDULE 7
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FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 080366-GU
BILL COMPARISONS - PRESENT & COMMISSION APPROVED RATES
Residential Usage
Average Usage: 20 therms per month

PRESENT RATES	COMMISSION APPROVED RATES
Customer Charge $8.00	**Customer Charge** $11.00
Energy Charge (Cents per Therm) 48.340	**Energy Charge (Cents per Therm)** 51.792
Purchased Gas Costs 2009 (Cents per therm) 40.000	**Purchased Gas Costs 2009 (Cents per therm)** 40.000
Conservation (Cents per therm) 6.768	**Conservation (Cents per therm)** 6.768

Therm Usage Increment: **2**

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Commission Approved Monthly Bill w/o Gas Cost	Commission Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
2	$9.10	$9.90	$12.17	$12.97	33.7%	31.0%	$3.07
4	$10.20	$11.80	$13.34	$14.94	30.8%	26.6%	$3.14
6	$11.31	$13.71	$14.51	$16.91	28.3%	23.3%	$3.20
8	$12.41	$15.61	$15.68	$18.88	26.3%	20.9%	$3.27
10	$13.51	$17.51	$16.86	$20.86	24.8%	19.1%	$3.35
12	$14.61	$19.41	$18.03	$22.83	23.4%	17.6%	$3.42
14	$15.72	$21.32	$19.20	$24.80	22.1%	16.3%	$3.48
16	$16.82	$23.22	$20.37	$26.77	21.1%	15.3%	$3.55
18	$17.92	$25.12	$21.54	$28.74	20.2%	14.4%	$3.62
20	**$19.02**	**$27.02**	**$22.71**	**$30.71**	**19.4%**	**13.7%**	**$3.69**
22	$20.12	$28.92	$23.88	$32.68	18.7%	13.0%	$3.76
24	$21.23	$30.83	$25.05	$34.65	18.0%	12.4%	$3.82
26	$22.33	$32.73	$26.23	$36.63	17.5%	11.9%	$3.90
28	$23.43	$34.63	$27.40	$38.60	16.9%	11.5%	$3.97
30	$24.53	$36.53	$28.57	$40.57	16.5%	11.1%	$4.04
32	$25.63	$38.43	$29.74	$42.54	16.0%	10.7%	$4.11
34	$26.74	$40.34	$30.91	$44.51	15.6%	10.3%	$4.17
36	$27.84	$42.24	$32.08	$46.48	15.2%	10.0%	$4.24
38	$28.94	$44.14	$33.25	$48.45	14.9%	9.8%	$4.31
40	$30.04	$46.04	$34.42	$50.42	14.6%	9.5%	$4.38

Purchased Gas Costs effective May 2009.
Bills do not include local taxes, franchise fees, or gross receipts taxes.

SCHEDULE 7
Page 3 of 6

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 080366-GU
BILL COMPARISONS - PRESENT & COMMISSION APPROVED RATES
GS-1
Average Usage: 20 therms per month

PRESENT RATES	COMMISSION APPROVED RATES
Customer Charge $15.00	Customer Charge $20.00
Energy Charge (Cents per Therm) 32.107	Energy Charge (Cents per Therm) 40.000
Purchased Gas Costs 2009 (Cents per therm) 40.000	Purchased Gas Costs 2009 (Cents per therm) 40.000
Conservation (Cents per therm) 2.918	Conservation (Cents per therm) 2.918

Therm Usage Increment: 5

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Commission Approved Monthly Bill w/o Gas Cost	Commission Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
5	$16.75	$18.75	$22.15	$24.15	32.2%	28.8%	$5.40
10	$18.50	$22.50	$24.29	$28.29	31.3%	25.7%	$5.79
15	$20.25	$26.25	$26.44	$32.44	30.6%	23.6%	$6.19
20	$22.01	$30.01	$28.58	$36.58	29.9%	21.9%	$6.57
25	$23.76	$33.76	$30.73	$40.73	29.3%	20.6%	$6.97
30	$25.51	$37.51	$32.88	$44.88	28.9%	19.6%	$7.37
35	$27.26	$41.26	$35.02	$49.02	28.5%	18.8%	$7.76
40	$29.01	$45.01	$37.17	$53.17	28.1%	18.1%	$8.16
45	$30.76	$48.76	$39.31	$57.31	27.8%	17.5%	$8.55
50	$32.51	$52.51	$41.46	$61.46	27.5%	17.0%	$8.95
55	$34.26	$56.26	$43.60	$65.60	27.3%	16.6%	$9.34
60	$36.02	$60.02	$45.75	$69.75	27.0%	16.2%	$9.73
65	$37.77	$63.77	$47.90	$73.90	26.8%	15.9%	$10.13
70	$39.52	$67.52	$50.04	$78.04	26.6%	15.6%	$10.52
75	$41.27	$71.27	$52.19	$82.19	26.5%	15.3%	$10.92
80	$43.02	$75.02	$54.33	$86.33	26.3%	15.1%	$11.31
85	$44.77	$78.77	$56.48	$90.48	26.2%	14.9%	$11.71
90	$46.52	$82.52	$58.63	$94.63	26.0%	14.7%	$12.11
95	$48.27	$86.27	$60.77	$98.77	25.9%	14.5%	$12.50
100	$50.03	$90.03	$62.92	$102.92	25.8%	14.3%	$12.89

Bills do not include local taxes, franchise fees, or gross receipts taxes.
Purchased Gas Costs effective May 2009.

ATTACHMENT A

SCHEDULE 7
Page 4 of 6

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 080366-GU
BILL COMPARISONS - PRESENT & COMMISSION APPROVED RATES

GS-2

Average Usage: 400 therms per month

PRESENT RATES	COMMISSION APPROVED RATES
Customer Charge $15.00	Customer Charge $33.00
Energy Charge (Cents per Therm) 32.107	Energy Charge (Cents per Therm) 40.000
Purchased Gas Costs 2009 (Cents per therm) 40.000	Purchased Gas Costs 2009 (Cents per therm) 40.000
Conservation (Cents per therm) 2.918	Conservation (Cents per therm) 2.918

Therm Usage Increment: 50

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Commission Approved Monthly Bill w/o Gas Cost	Commission Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
50	$32.51	$52.51	$54.46	$74.46	67.5%	41.8%	$21.95
100	$50.03	$90.03	$75.92	$115.92	51.7%	28.8%	$25.89
150	$67.54	$127.54	$97.38	$157.38	44.2%	23.4%	$29.84
200	$85.05	$165.05	$118.84	$198.84	39.7%	20.5%	$33.79
250	$102.56	$202.56	$140.30	$240.30	36.8%	18.6%	$37.74
300	$120.08	$240.08	$161.75	$281.75	34.7%	17.4%	$41.67
350	$137.59	$277.59	$183.21	$323.21	33.2%	16.4%	$45.62
400	$155.10	$315.10	$204.67	$364.67	32.0%	15.7%	$49.57
450	$172.61	$352.61	$226.13	$406.13	31.0%	15.2%	$53.52
500	$190.13	$390.13	$247.59	$447.59	30.2%	14.7%	$57.46
550	$207.64	$427.64	$269.05	$489.05	29.6%	14.4%	$61.41
600	$225.15	$465.15	$290.51	$530.51	29.0%	14.1%	$65.36
650	$242.66	$502.66	$311.97	$571.97	28.6%	13.8%	$69.31
700	$260.18	$540.18	$333.43	$613.43	28.2%	13.6%	$73.25
750	$277.69	$577.69	$354.89	$654.89	27.8%	13.4%	$77.20
800	$295.20	$615.20	$376.34	$696.34	27.5%	13.2%	$81.14
850	$312.71	$652.71	$397.80	$737.80	27.2%	13.0%	$85.09
900	$330.23	$690.23	$419.26	$779.26	27.0%	12.9%	$89.03
950	$347.74	$727.74	$440.72	$820.72	26.7%	12.8%	$92.98
1000	$365.25	$765.25	$462.18	$862.18	26.5%	12.7%	$96.93

Bills do not include local taxes, franchise fees, or gross receipts taxes.
Purchased Gas Costs effective May 2009.

ATTACHMENT A

SCHEDULE 7
Page 5 of 6

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 080366-GU
BILL COMPARISONS - PRESENT & COMMISSION APPROVED RATES
LVS
Average Usage: 1,768 therms per month

PRESENT RATES	**COMMISSION APPROVED RATES**
Customer Charge $45.00	**Customer Charge** $90.00
Energy Charge (Cents per Therm) 23.809	**Energy Charge (Cents per Therm)** 36.041
Purchased Gas Costs 2009 (Cents per therm) 40.000	**Purchased Gas Costs 2009 (Cents per therm)** 40.000
Conservation (Cents per therm) 2.051	**Conservation (Cents per therm)** 2.051

Therm Usage Increment: 400

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Commission Approved Monthly Bill w/o Gas Cost	Commission Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
400	$148.44	$308.44	$242.37	$402.37	63.3%	30.5%	$93.93
800	$251.88	$571.88	$394.74	$714.74	56.7%	25.0%	$142.86
1200	$355.32	$835.32	$547.10	$1,027.10	54.0%	23.0%	$191.78
1600	$458.76	$1,098.76	$699.47	$1,339.47	52.5%	21.9%	$240.71
2000	$562.20	$1,362.20	$851.84	$1,651.84	51.5%	21.3%	$289.64
2400	$665.64	$1,625.64	$1,004.21	$1,964.21	50.9%	20.8%	$338.57
2800	$769.08	$1,889.08	$1,156.58	$2,276.58	50.4%	20.5%	$387.50
3200	$872.52	$2,152.52	$1,308.94	$2,588.94	50.0%	20.3%	$436.42
3600	$975.96	$2,415.96	$1,461.31	$2,901.31	49.7%	20.1%	$485.35
4000	$1,079.40	$2,679.40	$1,613.68	$3,213.68	49.5%	19.9%	$534.28
4400	$1,182.84	$2,942.84	$1,766.05	$3,526.05	49.3%	19.8%	$583.21
4800	$1,286.28	$3,206.28	$1,918.42	$3,838.42	49.1%	19.7%	$632.14
5200	$1,389.72	$3,469.72	$2,070.78	$4,150.78	49.0%	19.6%	$681.06
5600	$1,493.16	$3,733.16	$2,223.15	$4,463.15	48.9%	19.6%	$729.99
6000	$1,596.60	$3,996.60	$2,375.52	$4,775.52	48.8%	19.5%	$778.92

Purchased Gas Costs effective May 2009.
Bills do not include local taxes, franchise fees, or gross receipts taxes.

SCHEDULE 7
Page 6 of 6

FLORIDA PUBLIC UTILITIES COMPANY
Docket No. 080366-GU
BILL COMPARISONS - PRESENT & COMMISSION APPROVED RATES
IS - Interruptible Service
Average Usage: 31,045 therms per month

PRESENT RATES	COMMISSION APPROVED RATES
Customer Charge $240.00	Customer Charge $280.00
Energy Charge (Cents per Therm) 10.039	Energy Charge (Cents per Therm) 23.484
Purchased Gas Costs 2009 (Cents per therm) 40.000	Purchased Gas Costs 2009 (Cents per therm) 40.000
Conservation (Cents per therm) 0.000	Conservation (Cents per therm) 0.000

Therm Usage Increment: 5,000

Therm Usage	Present Monthly Bill w/o Gas Cost	Present Monthly Bill with Gas Cost	Commission Approved Monthly Bill w/o Gas Cost	Commission Approved Monthly Bill with Gas Cost	Percent Increase w/o Gas Cost	Percent Increase with Gas Cost	Dollar Increase
5000	$741.95	$2,741.95	$1,454.20	$3,454.20	96.0%	26.0%	$712.25
10000	$1,243.90	$5,243.90	$2,628.40	$6,628.40	111.3%	26.4%	$1,384.50
15000	$1,745.85	$7,745.85	$3,802.60	$9,802.60	117.8%	26.6%	$2,056.75
20000	$2,247.80	$10,247.80	$4,976.80	$12,976.80	121.4%	26.6%	$2,729.00
25000	$2,749.75	$12,749.75	$6,151.00	$16,151.00	123.7%	26.7%	$3,401.25
30000	$3,251.70	$15,251.70	$7,325.20	$19,325.20	125.3%	26.7%	$4,073.50
35000	$3,753.65	$17,753.65	$8,499.40	$22,499.40	126.4%	26.7%	$4,745.75
40000	$4,255.60	$20,255.60	$9,673.60	$25,673.60	127.3%	26.7%	$5,418.00
45000	$4,757.55	$22,757.55	$10,847.80	$28,847.80	128.0%	26.8%	$6,090.25
50000	$5,259.50	$25,259.50	$12,022.00	$32,022.00	128.6%	26.8%	$6,762.50
55000	$5,761.45	$27,761.45	$13,196.20	$35,196.20	129.0%	26.8%	$7,434.75
60000	$6,263.40	$30,263.40	$14,370.40	$38,370.40	129.4%	26.8%	$8,107.00
65000	$6,765.35	$32,765.35	$15,544.60	$41,544.60	129.8%	26.8%	$8,779.25
70000	$7,267.30	$35,267.30	$16,718.80	$44,718.80	130.1%	26.8%	$9,451.50
75000	$7,769.25	$37,769.25	$17,893.00	$47,893.00	130.3%	26.8%	$10,123.75

Purchased Gas Costs effective May 2009.
Bills do not include local taxes, franchise fees, or gross receipts taxes.

PSC Order No.
1983-12290
1983-12356
1983-12654
1984-12857
1984-12864
1984-12866
1984-13495
1984-13528
1984-13538
1984-13918
1985-14929
1986-16963
1987-18029
1988-18642
1988-18736
1988-20330
1989-22115
1990-22585
1990-23922
1991-24004
1991-24005
1992-25679
1993-1554
1994-1199
1995-0475
1996-0461
1997-0499
1999-0073
2000-0293
2002-0501
2005-0902
2010-0153

ATTACHMENT B

1983 Fla. PUC LEXIS 458

Florida Public Service Commission

July 22, 1983

DOCKET NO. 820449-TP; ORDER NO. 12290, 83 FPSC 400

FL Public Service Commission Decisions

Reporter
1983 Fla. PUC LEXIS 458 *

In re: Petition of Southern Bell Telephone and Telegraph Company for a represcription of depreciation rates

Core Terms

depreciate, salvage, remaining life, service life, was, estimate, plant, customer, network, cost, formula, amortize, deficit, retirement, cable, embed, fiber, replacement, telephone, calculate, switchers, salvage value, subaccounts, staff, electronic, digital, station, aerial, annual, copper

Counsel

[*1]

William B. Barfield, 666 Northwest 79th Avenue, Miami, Florida 33126; Earl B. Hadlow, Mahoney, Hadlow & Adams, Post Office Box 4099, Jacksonville, Florida 32202; and Fred A. Walters, 4300 Southern Bell Center, 675 West Peachtree Street, N.E., Atlanta, Georgia 30375, appearing on behalf of Southern Bell Telephone and Telegraph Company.

Jack Shreve, Kenneth A. Hoffman, and Benjamin H. Dickens, Office of the Public Counsel, Room 4, Holland Building, Tallahassee, Florida 32301, appearing on behalf of the Citizens of the State of Florida.

Susan F. Clark, 101 East Gaines Street, Tallahassee, Florida 32301, appearing on behalf of the Florida Public Service Commission staff.

Prentice P. Pruitt, 101 East Gaines Street, Tallahassee, Florida 32301, appearing as counsel to the Commissioners.

Panel: The following Commissioners participated in the disposition of this matter: JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS

Opinion

ORDER APPROVING DEPRECIATION RATES

BY THE COMMISSION:

Background and Summary of Decision

This proceeding was initiated by a petition of Southern Bell Telephone and Telegraph Company (the Company or Southern Bell) for a represcription of depreciation rates. **[*2]** The Company's petition was filed pursuant to *Section 350.115, Florida Statutes*, which requires this Commission to set fair and reasonable depreciation rates and charges, and Florida Administrative Code Rules 25-4.175 and 25-4.176. The request was for a revision of depreciation rates and capital recovery schedules currently applicable to Southern Bell's operations in Florida that would have increased operating expenses on an annual basis by approximately $270 million (intrastate expenses by approximately $162 million). In addition to the establishment of new service lives and salvage values, the Company requested the adoption of a new formula for calculating depreciation, the age/life formula. The Company's petition was supported by a depreciation study.

On November 15, 1982, the Office of Public Counsel filed a Notice of Intervention. On November 18, 1982, Order No. 11337, acknowledging the intervention, was issued. Public Counsel opposed the request for new depreciation rates. Public Counsel's position was that the Company's age/life formula had a tendency to allow over-recovery of investment and that the Company's estimates of salvage **[*3]** values and service lives were speculative and unjustified. Public Counsel opposed any change in depreciation rates.

A prehearing conference was held before Commissioner Joseph P. Cresse on April 4, 1983. Hearings were held on April 14 and 15, 1983. An additional hearing was held on June 14, 1983, on the issue of whether the investment in Official Telephones (Account 231.2) and Pay Stations (Account 231.3) was prudent.

At the hearings held on April 14 and 15, 1983, the Company presented the testimony of Messrs. Snelling, Andrews, Lipske and Prophitt. Mr. Snelling presented testimony describing the Company's position that Southern Bell's network must change its basic character over the next two decades in order to continue to provide basic telephone service at affordable rates and to meet the evolving needs of the Florida subscriber. Mr. Victor Andrews' testimony related to the Company's depreciation rate proposals, the adequacy of its depreciation reserves, and the effect of these on the Company's financial integrity. Mr. Lipske testified on the adequacy of past depreciation policies and reserve factors affecting capital recovery needs of the Company, and gave recommendations **[*4]** on future depreciation policies. Finally, Mr. Prophitt sponsored the Company's depreciation study with specific proposals on the formula to use in developing depreciation rates and on proposed service lives, salvage values and depreciation rate schedules.

Public Counsel presented the testimony of Dr. Walter Bolter. Dr. Bolter commented on Southern Bell's position regarding the effect of competition on the Company's ability to recover capital, the age/life formula, the life cycle method for equipment life projections, and on whether the effects of divestiture and related market changes had been taken into account in estimating life and salvage factors. Dr. Bolter concluded that the age/life formula for determining depreciation rates was inappropriate and the Company had not justified a change in depreciation rates.

Finally, Mr. Mark Wilkerson appeared on behalf of the Commission staff. Mr. Wilkerson presented testimony on the inappropriateness of the age/life formula and presented proposals for new depreciation rates and the treatment of possible reserve deficiencies. The staff also called Mr. Roderick G. Turner, Division Manager of the Comptrollr's Department for Southern Bell, **[*5]** as an adverse witness. Mr. Turner answered questions relating to the recording of depreciation since January 1, 1981, and relating to entries in certain subaccounts.

We have concluded that a change in depreciation rates is necessary and we hereby approve the appended rates. However, we reject the age/life formula for calculating depreciation rates for reasons explained herein. In reaching our decision on new depreciation rates, we are ordering the amortization of current depreciation reserve deficits. Amortizing these deficits eliminates the need to use different depreciation rates for embedded plant and new plant. We have also ordered Capital Recovery Schedules covering switching entities retiring in the 1983-1985 time period. We have not changed depreciation rates for embedded Customer Premises Equipment (CPE) which will be transferred to some affiliate of American Telephone and Telegraph (AT&T) no later than January 1, 1984.

<u>The Age/Life Formula</u>

In its petition, the Company requested the adoption of a new formula for calculating the appropriate reserve level and depreciation rates. Their proposal is called the "age/life formula" . Mr. H. G. Prophitt of Southern Bell **[*6]** presented testimony in support of the formula.

The evidence was conclusive that the formula, as proposed, is inappropriate for calculating the depreciation reserve when there is a dispersion of retirements. Historically, average service lives have been used for setting depreciation rates. The age/life formula as a measurement of the depreciation reserve assumes all plant previously retired has been fully recovered. The introduction of the age/life reserve measurement now would show a reserve deficiency due to prior retirements at less than average age. This would be true even though the early retirements were anticipated in setting prior rates. The result is an overstatement of the reserve requirement for the particular account.

The use of the age/life concept to calculate a depreciation rate was also demonstrated to be defective. Mr. Wilkerson, testifying on behalf of the Commission staff, demonstrated that the use of the formula led to over-recovery of capital. Mr. Wilkerson further demonstrated that even with annual revisions, over-recovery was probable. Public Counsel's witness, Dr. Walter Bolter, concurred in Mr. Wilkerson's assessment of the formula. Mr. **[*7]** Prophitt admitted that annual revisions were necessary to prevent over-recovery.

The need for annual revisions to avoid over-recovery contradicts the Company's argument that the formula is a simpler method than the remaining life method. The continued use of our remaining life approach is, in our opinion, correct. The remaining life approach does not require annual rate revisions and does not have the characteristic of over-recovery, but, rather, that of assuring full recovery, no more and no less.

Company Justification for More Accelerated Depreciation Rates

Southern Bell, through the testimony of Mr. Richard K. Snelling, presented the factors which necessitated accelerating current depreciation rates. According to Mr. Snelling, the prospect of competition in the areas of intercity services and high speed data services for large business customers requires the Company to modernize the Company's network to meet needs of these customers. If the needs of these customers are not met by Southern Bell, these customers will leave the network and revenues will be lost. The Company alleged that 5% of its customers generate 50% of its revenues and these revenues make it possible **[*8]** to maintain universal service at affordable rates.

For those customers needing large capacity intercity services and high speed data transmission, and for those residential and business customers who will want to use telephone lines to transmit data, the current network may be, or may rapidly become, obsolete. The estimated service lives and salvage values proposed by the Company recognize this technological obsolesence.

Southern Bell's plans are to use funds generated from authorized depreciation rates to finance current and future network modernization. Southern Bell maintains all customers will benefit from the modernization because it is anticipated that it will be more economical to engineer, place, maintain and repair an all digital network.

Change in Depreciation Rates

While we recognize that maintaining Southern Bell's customer base is important to maintain universal service, we question the fairness of requiring all customers of Bell to pay for capabilities only 5% will need. A balance must be struck between the needs of the 5% for a more advanced network and the needs of the ordinary telephone subscriber. The Company's plans to modernize the entire **[*9]** network to meet the needs of 5% does not begin to find the proper balance. If it is necessary for the Company to make substantial investments to serve just 5% of its customers, the Company has the obligation of demonstrating that those costs are or will be paid by those customers, or that it is beneficial to the remaining customers to bear some of those costs in order to retain the lucrative 5%. Additionally, if it is more economical to engineer, place, maintain and repair an all digital network, we would expect the Company to present evidence to this effect by demonstrating the obsolesence of existing network and the economic validity of abandoning plant. The Company failed to present any competent, substantial testimony on these two points.

It was suggested by Public Counsel that no change in depreciation rates be made at this time. With the exception of the rates for embedded CPE, all rates were reviewed and those requiring changes were changed. Although the prospects of divestiture, deregulation and access charges may affect the useful life and salvage value of equipment, we have found that the present depreciation rates are inadequate and do not allow for proper capital **[*10]** recovery. With regard to most embedded CPE, the depreciation rates will remain unchanged. Because embedded CPE (with the exception of official telephones and PBXs, pay stations, telecommunication devices for the deaf and, under our rules, primary instruments) will be transferred to an affiliate of AT&T, and perhaps deregulated, we feel it is inappropriate to change depreciation rates for this equipment. The effect of these circumstances on the service life and salvage value of the equipment is unclear. At the hearing, the parties agreed that the rates for such CPE should not be changed and we hereby concur in that agreement.

We note that other equipment and assets will be transferred to AT&T on January 1, 1984. However, unlike embedded CPE, most of the equipment and assets have not been identified, and we anticipate that the equipment and assets will be used to provide service under regulation. Though the owner will change, the plant should continue to provide service for a certain service life and depreciation rates should be set accordingly.

Because we have elected not to set new depreciation rates for embedded CPE to be transferred, it was necessary to have the investment **[*11]** and reserves in Accounts 231 and 234 reallocated to the new subaccounts. These new subaccounts are those specified in Rule 25-4.17, Florida Administrative Code. In a late-filed exhibit, the Company did the reallocation. We were concerned that the allocations were inappropriate. However, at the subsequent hearing held on June 14, 1983, evidence substantiating the investment in equipment in these accounts was provided. Based on that evidence, we believe the reallocation of the investment and reserve is substantially correct.

<u>Estimates of Remaining Life of Investment</u>

The Company's life cycle approach to estimating lives is predicated on the rapid change out of existing plant to provide a competitive broadband digital network. This results in short remaining lives for many plant accounts.

In staff's opinion, and we concur in that opinion, the shortened lives are specifically designed to rapidly replace the existing network with state-of-the-art technology as it becomes available, rather than as the majority of customers require it. The testimony of Mr. Snelling showed that the rate of replacement indicated by the estimates of remaining life was not consistent with **[*12]** the Company's plans for replacement or customer needs. The Company's construction plans, especially in the area of replacement of copper cable, did not coincide with estimates of remaining life. Additionally, it was shown that customer needs for a more advanced network could be met by overlays, rather than total replacement of equipment.

While we agree with the Company that technological changes and the advent of competition are factors to be taken into consideration, we disagree with the extent to which they have considered that impact in estimating the remaining life of plant. The remaining life approved herein for the various accounts recognizes the need for a gradual modernization of the network.

<u>Appropriate Depreciation Reserve Level and Correction of the Reserve Deficit</u>

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current reserve levels and what the reserve levels should be using the new depreciation rates. We have calculated the net reserve deficit to be $265,600,000 on a composite basis. While it is possible to make that correction through the new depreciation rates allowed **[*13]** for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the Company to separately recover the reserve deficit, we are bringing the booked reserves for each account up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant, which is estimated to be 16 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 16-year period is $142.6 million, and the amount to be amortized over a 5-year period is $123 million.

The company is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization **[*14]** of the two deficit amounts. No further deficits should be included in these accounts without Commission approval. Likewise, each depreciable account's book reserve should be restated to the theoretical level calculated by using the newly authorized depreciation rates (and brought forward from that point).

New Depreciation Rates and Capital Recovery Schedules

We have not included in the reserve deficit calculation the deficits relating to investments in electromechanical and electronic switchers which will be retired in the 1983 to 1985 time period. For those investments, we are ordering capital recovery schedules. The capital recovery schedules are shown on Attachment A. We have also not included the reserve deficits associated with embedded CPE (Accounts 231.1 and 234.1) which will be transferred to AT&T.

Effective Date

We have decided that the effective date for the new depreciation rates should be July 1, 1983. The Company proposed this date for purposes of matching expenses and revenues. This would be accomplished because the pending rate case, Docket No. 820294-TP, was scheduled for completion in the June-July time period. The Commission has generally **[*15]** used a January 1 effective date since this usually coincides with the accounting period. However, in this instance we believe a July 1, 1983 date is appropriate because the Company's study was calculated for that implementation date, and a decision on the rate award will roughly coincide with July 1, 1983.

Company Recordkeeping

Staff investigation and evidence presented in this docket indicates that the Company's recordkeeping is deficient in some areas. (Exhibit 12, the Commission staff audit.) Deficiencies in recordkeeping were found in the Central Office subaccounts, a Station Appeaaratus subaccount, the Aerial Wire Account and the Computer Account. Although the deficiencies detected in this docket do not appear to be material in nature, they may be indicative of problems of a larger magnitude. If there are problems of a substantive nature, the accuracy of the depreciation reserves, life and salvage factors and investment are affected. This in turn influences the accuracy of the depreciation rates prescribed. Since staff will be performing a special study of the Company's continuing property records, we will take no action on the matter at this time.

Costs of Divestiture **[*16]**

We take this opportunity to again remind the Company of its obligations under Order No. 11969, issued in Docket No. 820263-TP. Pursuant to that Order we would expect the Company to keep track of costs incurred to comply with the Modified Final Judgment issued by Judge Green. It appears that modifications to the network are required by the MFJ. The modification costs should be included in the reports. Those costs would include capital expenditures as well as costs which are expensed.

I. New Life and Salvage Factors to be Used in Remaining Life Formula

A. Building and Central Office Equipment

1. Buildings (Account 212)

The Company proposed using the same life and salvage factors (44 years and a 3% average net salvage) used in the 1980 represcription and we find this to be an acceptable proposal. This results in a remaining life of 38 years.

2. Manual (Account 221-17C)

The Company proposed average service life of 7.5 years, average remaining life of 3.7 years, and zero salvage value is acceptable.

3. Step-by-Step (Account 221-37C)

The Company plans to retire certain electromechanical switchers during the 1983-1985 time period. The **[*17]** replacement of these switchers within this time period is appropriate because of high maintenance and trunking costs, extensive space requirements, the extensive rearrangements necessary to accomodate growth, and lack of capability to provide custom calling features.

Because of this short time period, a capital recovery schedule is approved to recover the remaining investment in these switchers over the next three years. The net investment to be amortized is $36,133,000. This schedule will be effective from July 1, 1983 to June 30, 1986 and will be maintained as a separate subaccount. Quarterly reports beginning September 30, 1983 showing plant balances and activity, reserve balances and activity, and any changes in plans for this equipment or in anticipated net salvage are required. Based on the information supplied in these reports, the recovery programs can be modified as required to prevent under- or over-recovery of investment. If significant changes occur before the first quarterly report, they should be immediately reported to the Commission's Auditing and Financial Analysis Department.

For the remaining investment in this account, we find an average service life of 7.5 **[*18]** years, an average remaining life of 4.6 years, and a future net salvage of negative 8% to be appropriate for use in determining rates.

4. Crossbar (Account 221-47C)

As with the step-by-step switchers, we find the replacement schedule of this Central Office Equipment to be prudent. As with step-by-step switchers, the net investment should be amortized over the next three years. The 3-year capital recovery schedule begins on July 1, 1983 and will continue through June 30, 1986 to recover this net investment. Quarterly reports beginning September 30, 1983, containing the same information required for step-by-step investment, shall be filed. Likewise, this schedule will be maintained as a separate subaccount.

For the remaining investment in this account, we find an average service life of 9.4 years, an average remaining life of 6.0 years, and a future net salvage of 3% to be appropriate.

5. Circuit - Other (Account 221-57C)

The Company's projected replacement for this equipment is predicated on their desire for a rapid transformation of their network to an all digital network. However, the Company's 10.4 year projected life assumes a more accelerated retirement pattern **[*19]** than is supported by the Company's Forecasted Retirements of Existing Investment. Additionally, the testimony did not demonstrate that the majority of telephone subscribers will require the level of data transmission capability or the modern services to be afforded by the new network as rapidly as indicated by the 10.4-year projected life. We find a 14-year projected life to be more reasonable.

The use of the 14-year projected life results in a 14.5-year average service life and an 11.1-year average remaining life. Additionally, we find a zero future net salvage for analog circuit equipment and a 5% future net salvage for digital or digital compatible equipment to be appropriate. These salvage values result in a composite 3% future net salvage for the account.

6. Circuit - Digital Data Systems (Account 221-57C)

We find the Company proposed average service life of 12 years and the average remaining life of 11.1 years to be reasonable. However, the future net salvage of negative 4% appears to be too low given the fact that over the four years this account has been in use, the gross salvage has averaged 29%. Salvage value can be expected to rapidly decrease in **[*20]** this account due to its sensitivity to the competitive market. Therefore, we find a future net salvage of 2% to be reasonable.

7. COE Radio (Account 221-67C)

As with Subaccount 221-57C above, the service life of equipment in this account is affected by competition from other entities providing services which utilize the type of equipment in this account. The Company's projected life of 15 years is reasonable based on past experience of this account. This estimate of projected life results in an average remaining life of 8.9 years. We find a negative 13% future net salvage to be appropriate since it is in line with the recent activity in this account.

8. Electronic Switching (Account 221-77C)

A three-year recovery schedule is approved for a small electronic switcher (Boca Raton Sandalfoot) scheduled for retirement in 1985. This retirement was examined and found prudent due to exhaust of capacity. The net investment is $3,358,133. This schedule begins July 1, 1983 and will continue through June 30, 1986. Quarterly reports beginning September 30, 1983, containing the same information required for step-by-step and crossbar investments, shall be filled. Likewise, **[*21]** this schedule will be maintained as a separate subaccount.

For the remaining investment in this account, we find a 19.5 year average service life and a 16.3-year average remaining life appropriate due to the fact that the existing large electronic switchers can be converted to digital by a change-out of their processors (central computer). Taking into consideration the increasing age of the electronic offices and the advance of technology, a 9% future net salvage is approved.

9. Electronic Switching Digital (Account 221-77C)

The first generation of small local digital switchers is projected to be replaced about the year 2000. For this reason, and lacking additional information, we find an average service life of 17.5 years and zero net salvage appropriate. Because this is a newly established account, the average remaining life approximates the average service life. Also, as this account gains some experience from this switcher or additional switchers of a larger or more complex nature, these life and salvage components should be re-examined.

B. Terminal Equipment

As stated previously, we are not changing depreciation rates for embedded CPE which will be transferred **[*22]** to AT&T.

The life and salvage values proposed by the Company for the remaining equipment are acceptable to us and are hereby approved. Those values are as follows:

1. Official Telephones (Account 231.2)

8 years average service life; 6 years average remaining life; 1% future net salvage

2. Pay Stations - Exchange (Account 231.3)

9.6 years average service life; 7.8 years average remaining life; 1% future net salvage.

3. Primary Investment (Account 231.4)

6 years average service life; 1% future net salvage. (This is a new account, therefore there is no remaining life figure).

4. Telecommunications Devises For The Deaf (Account 231.5)

6.1 years average service life; 5 years average remaining service life; 1% future net salvage.

5. Station Connections

20 years average service life; zero future net salvage.

6. Official PBX (Account 234.2)

6.4 years average service life; 4.5 years average remaining life; 2% future net salvage.

7. Multiplexing (Account 234.3)

6.4 years average service life, 4.5 years average remaining life; 2% future net salvage.

C. Outside Plant

The Company's proposals for depreciation rates for outside **[*23]** plant were predicated on the rapid replacement of the existing copper network with fiber optics to provide a broadband high speed data network. The ability to provide transmission of high speed data will be a service which the Company maintains it must offer to retain the lucrative 5% of its customers. About $112 million of the Company's proposed increase in expenses is due to the increase in depreciation rates for copper wire dictated by the proposed rapid changeover to fiber.

At the hearing, the evidence demonstrated that: fiber optics is not necessary to the provision of simple telephone service; change out to fiber is not necessary to accomodate the service needs of the 5%, an overlay of fiber is sufficient for customers requiring it; and the rapid change out contemplated by the accelerated depreciation rates was not consistent with Company construction plans.

It was suggested that the replacement of copper with fiber may result in lower maintenance and therefore reduce costs to ratepayers in the long run. This was not shown to be the case at the present time. If at any time the Company can show it is economically efficient to replace all copper wire with fiber, **[*24]** the Commission can establish a mechanism for recovery of investment in the abandoned copper. The Company would have to show that the cost of installing the fiber, plus the cost of maintenance and depreciation on the fiber, plus the cost of amortizing the remaining investment in copper was less than using and maintaining the existing copper plant. It would then be beneficial to the ratepayers to change out the existing plant.

Our approved estimates of average service lives and salvage value for the accounts described below recognize some foreshortening of service lives due to technological change and competition. We believe the estimates to be more realistic in light of the testimony and evidence presented.

1. Poles (Account 241)

Recently, life indications for this account have been about 40 years. However, the move toward buried cable has affected depreciation rates for this account and a 40 year life for wood poles in Florida is probably unrealistic. The staff recommended an average service life of 30 years which results in an average remaining life of 25 years, and we hereby approve these estimates.

We have elected not to change future net salvage value currently prescribed **[*25]** for this account (negative 45%) because the cost of removal as experienced for this account, and as proposed, does not appear to be justified. We cannot comprehend why the engineering costs amount to 49% of the cost of removal when removal is performed by outside contractors. We have found that there is a wide variation in the net salvage value of poles between the various companies we regulate. The staff is pursuing an audit review to determine the appropriate costs of removal and the resultant future net salvage value. Until the review is complete the currently prescribed net salvage will remain, even though it may result in an artificially low depreciation reserve. The Company is hereby put on notice that the reserve for this account may be adjusted after our investigation into removal costs.

2. Aerial Cable - Exchange (Account 242.1)

While we disagree with the Company's projections, we do believe that the service life for equipment in this account should be shortened. Accordingly, we approve an average service life of 21 years which results in an average remaining life of 17.2 years. The Company's proposed future net salvage of negative 26% is acceptable and, therefore, **[*26]** is approved.

3. Aerial Cable - Toll (Account 242.1)

We expect fiber optics to have a significant impact on this account. Therefore, we are approving considerably shortened service lives for this account. We find an average service life of 20 years to be acceptable. The resultant average remaining life is 9 years. The Company's future net salvage estimate of 19% is acceptable.

4. Underground Cable - Exchange (Account 242.2)

We find the Company's proposal of a future life of 16.1 years for this account to be unsupported. However, we do find the 40-year future life currently used for calculating depreciation rates for this plant to be unrealistic. We find an average service life of 32 years to be more appropriate recognizing some impact of fiber. The average remaining life approved is 27 years. The Company's estimate of future net salvage of negative 5% is acceptable.

5. Underground Cable - Toll (Account 242.2)

As with aerial toll cable, we believe the impact of fiber optics will be significant on this account. We agree with Mr. Wilkerson that the FCC engineer's estimate of a 20-year future service life is reasonable. The resulting average service **[*27]** life is 22 years, and the average remaining life is 12.9 years. We approve the Company's future net salvage estimate of 11%.

6. Buried Cable - Exchange (Account 242.3)

Again, we find the Company's proposed future life projections for this account to be too short. Some shortening is justified and we therefore approve a 25-year future life projection which results in an average service life of 25 years and a remaining life of 21 years. We believe the Company's estimate of future net salvage of negative 15% future net salvage represents too high a cost of abandonment. Some costs resulting from closure of pedastals, terminals and attendant equipment can be expected. We hereby approve a negative 5% future net salvage on the basis that as the larger cable retirements occur, cost of removal as a percent of the investment will be relatively low.

7. Buried Cable - Toll (Account 242.3)

Based on the same rationale as that for aerial and underground toll cable, we hereby approve a future life of 20 years. This produces an average service life of 23 years and a remaining life of 13.6 years. The proposed future net salvage value of negative 3% is approved.

8. Submarine **[*28]** Cable (Account 242.4)

Past experience regarding equipment in this account shows that the equipment is relatively trouble free and does not require replacement. Additionally, we do not expect the equipment in this account to be influenced significantly in the short-term by fiber optics. However, in the long-term, there may be some impact from fiber. Based on these factors, we approve a decrease from the current average service life of 27 years to 25 years. This results in an average remaining life of 16.7 years. The approved future net salvage is negative 2%.

9. Aerial Wire (Account 243)

The cable in this account is used to serve rural areas where slow growth is forecasted, as temporary extensions in areas of rapid growth, and for temporary service to construction sites or during cable repairs or relocations. We believe the currently prescribed 5-year average service life is still appropriate. The resultant average remaining life is 3.3 years. Experience on salvage value for equipment in this account for the past 5 years shows a negative 24% future net salvage to be reasonable.

10. Underground Conduit (Account 244)

We are approving the Company's proposals **[*29]** for this account. The average service life is 65 years, the remaining life is 58 years, and the future net salvage is 5%.

D. General Equipment

1. <u>Furniture and Office Equipment</u> (Account 261.01)

This account is made up of office furniture and miscellaneous items (78%) and typewriters and office machines (22%). The trend to modular furniture and the introduction of more efficient word processing and calculating equipment are changes affecting the estimated service life for equipment in this account. Based on current life indications of the account, we hereby approve a 20-year future life for the office furniture portion of the account and a 13-year future life for the office machines portion. This results in a composite average service life of 17.6 years and an average remaining life of 14.4 years for the account. The Company's estimate of negative 2% future net salvage is approved.

2. <u>Computers</u> (Account 261.03)

After considering the historic retirement pattern of this account and the equipment currently in this account, we hereby approve an average service life of 6.8 years, which results in an average remaining life of 4.1, and a future net salvage of zero. **[*30]**

3. <u>Motor Vehicles</u> (Account 264)

This account includes light motor vehicles (passenger cars, small trucks), heavy duty trucks and special purpose vehicles. Using separately estimated life and salvage factors for the light vehicles and for the heavy vehicles, we have determined the overall average service life to be 7.9 years, with an average remaining life of 4.5 years. The future net salvage value is 22%.

4. <u>Tools and Other Work Equipment</u> (Account 264)

We are approving the Company's proposals for life and salvage factors for this account. They are: 14.6 years average service life, 12.8 years remaining life, and 2% future net salvage.

In consideration of the foregoing, it is hereby

ORDERED by the Florida Public Service Commission that the depreciation rates and capital recovery schedules attached hereto as Appendix A are hereby approved, effective July 1, 1983, for Southern Bell Telephone and Telegraph Company. It is further

ORDERED that the composite reserve deficit found to exist be recovered through the two amortization schedules approved herein. It is further

ORDERED that the Company file the quarterly reports regarding the capital recovery schedules authorized **[*31]** herein. It is further

ORDERED that Southern Bell Telephone and Telegraph Company establish the records for recovery of the reserve deficit as required herein.

By Order of the Florida Public Service Commission this 22nd day of JULY, 1983.

ATTACHMENT A

Approved Depreciation Rates

Avg. Rem. Life	**Future Net Salvage**	**Theoretical Reserve**	**Rem. Life Rate**

		(Yrs)	(%)	(%)	(%)
212	Buildings	38	4	12.4	2.2
221	Manual	3.7	(8)	56.2	14.0
	Step-by-Step	4.6	(8)	45.9	13.5
	Crossbar	6.0	(3)	40.6	10.4
	Circuit	11.1	3	23.74	6.6
	Digital Data Systems	11.1	2	10.31	7.9
	Radio	8.9	(13)	48.92	7.2
	Electronic	16.3	4	17.76	4.8
	ESS Digital	17.5	0		5.7
231	Station Apparatus				
	Embedded CPE				12.1
	Official CPE	6.0	1	25.1	12.3
	Pay Stations	7.8	1	19.44	10.2
	Primary	6.0	1	0	16.5
	Deaf	5.0	1	18.5	16.1
232	Station Connections				
	Outside Wire				5.0
234	Large PBX				
	Embedded CPE				13.8
	Official PBX	4.5	2	32.75	14.5
	Multiplexing Equip.	4.5	2	32.75	14.5
241	Pole Lines	25	(45)	25.0	4.8
242.1	Aerial Cable-Exch.	17.2	(26)	24.52	5.9
	-Toll	9	19	42.3	4.3
242.2	Undg. Cable-Exch.	27	(5)	15.9	3.3
	-Toll	12.9	11	36.11	4.1
242.3	Buried Cable-Exch.	21	(5)	16.8	4.2
	-Toll	13.6	(3)	43.16	4.4
242.4	Submarine Cable	16.7	(2)	33.53	4.1
243	Aerial Wire	3.3	(24)	41.5	25.0
244	Undg. Conduit	58	(5)	12.2	1.6
261	Furn. & Ofc. Equip.				
	Storeroom & Reg.	14.4	2	17.36	5.6
	Computers	4.1	0	39.73	14.7
264	Veh. & Other Work Equip.				
	Motor Vehicles	4.5	21	34.45	9.9
	Other Work Equip.	12.8	2	14.8	6.5

[*32]

ATTACHMENT B

The recovery schedules and associated expense as shown below were approved. It should be noted that the associated expenses and amortization period were approved, not a rate to be applied to surviving investments. All figures shown are on a total company basis and are not separated into Interstate and Intrastate.

Approved Recovery Schedules

I. Step-By-Step Switchers

Scheduled For Retirement in 1983-1985

Investment	$36,081,000
Less net salvage of (8)%	(2,886,000)
Less associated reserve	2,834,000
Net Plant	$36,133,000
3 year amortization	$1,003,694 monthly expense
	$12,044,333 annual expense

II. Crossbar Switchers

Scheduled For Retirement In 1983-1985

Investment	$59,174,000
Less net salvage of (3)%	(1,775,000)
Less associated reserve	876,000
Net Plant	$60,073,000
3 year amortization	$1,668,694 monthly expense
	$20,024,333 annual expense

III. Electronic Switchers

Scheduled For Retirement in 1983-1985

Investment	$3,727,000
Less net salvage of 2%	75,000
Less associated reserve	294,000
Net plant	$3,358,000
3 year amortization	$93,278 monthly expense
	$1,119,333 annual expense

FL Public Service Commission Decisions

End of Document

Florida Public Service Commission

August 12, 1983

DOCKET NO. 810100-EU; ORDER NO. 12356, 83 FPSC 182; 55 P.U.R.4th 1

FL Public Service Commission Decisions

Reporter
1983 Fla. PUC LEXIS 403 *

In re: *Investigation* of the appropriate accounting and ratemaking treatment of decommissioning and depreciation costs of nuclear powered generators

Core Terms

decommissioning, cost, company, accrual, dismantlement, revise, annual, depreciate, was, dollar, fuel, calculate, methodology, staff, base rate, akin, rate case, additional revenue, inflate, conjunction, interim, nuclear, has, kwh, additional expense, accrue, energy, plant

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[*1]

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Paul Sexton, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301-8153, For the Commission Staff

Prentice P. Pruitt, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301-8153, Counsel to the Commissioners

Panel: The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, CHAIRMAN; JOSEPH P. CRESSE, KATIE NICHOLS

Opinion

Pursuant to notice, public hearings were held before Commissioners Gerald L. Gunter, Joseph P. Cresse and Katie **[*2]** Nichols on December 6, 1982, January 13, 1983 and July 13, 1983.

ATTACHMENT B

ORDER CONCLUDING INVESTIGATION

BY THE COMMISSION:

I. BACKGROUND

This proceeding was initiated on the Commission's own motion by ***Order*** No. 10067, issued June 16, 1981. ***Order*** No. 10067 set forth the basic issues to be addressed in this ***investigation***. Those issues were broadened by the prehearing ***order*** (***Order*** No. 10557, issued January 21, 1982). A public hearing was held on February 8, 1983 and a final ***order*** (***Order*** No. 10987) was issued.

In ***Order*** No. 10987 we ***concluded***:

(1) The treatment of decommissioning costs as a part of depreciation is insufficient to monitor the expense. Decommissioning costs should be accounted for separately and that portion of the accumulated provision for depreciation related to decommissioning should be segregated.

(2) Decommissioning costs should be reviewed and, if necessary, changed no less often than every five years.

(3) Decommissioning costs should be accounted for in an internally funded reserve in ***order*** to insure adequate funds to pay for decommissioning.

(4) Changes in revenue requirements to recognize changes in decommissioning expense should not be **[*3]** delayed until the Companies' next rate cases. We direct the staff to present us with a plan for recovering the revised costs of decommissioning the four nuclear units in Florida.

Order No. 10987 then required Florida Power & Light Company and Florida Power Corporation to begin accounting for decommissioning costs consistent with the ***order*** and utilize a funded reserve. ***Order*** No. 10987 held the docket open pending a staff recommendation on effectuating any revenue requirement changes pertaining to decommissioning expense.

II. ***INVESTIGATION*** EXPANDED

By ***Order*** No. 11122, issued August 30, 1982, we expanded the ***investigation*** into decommissioning costs and took into consideration the treatment of depreciation costs as well. ***Order*** No. 11122 and the prehearing ***order*** (***Order*** No. 11381) identified the following new issues:

1. Whether decommissioning and depreciation costs should be accounted for on a units of production basis;

2. If such costs are accounted for on a units of production basis, how should the allocation of costs be accomplished;

3. How should the impact of events (such as a shutdown) on productive life be accounted for;

4. What production capacity factors should **[*4]** be used;

5. What depreciation and decommissioning costs are currently in base rates;

6. What mechanism should be used to provide for recovery of depreciation and decommissioning costs?

7. Whether the reserve should be funded net of taxes.

A hearing was held on these issues on December 6, 1982. It became apparent at that hearing that additional data was required before a final decision could be reached as to the amount to be accounted for under either a units of production or straight line basis. A further hearing was held on January 13, 1983, at which time additional information was received.

III. INTERIM RULING

At the January 13, 1983, hearing we voted on several issues raised by ***Order*** Nos. 11122 and 11381. That vote is reflected herein as follows:

Issue 1. Units of Production versus Straight Line

FPL, FPC and Staff proposed that the straight line method of accounting for decommissioning costs and depreciation expense be retained. Public Counsel proposed that a units of production method be used.

No testimony was presented in favor of a units of production basis of accounting for decommissioning costs or depreciation expense. Mr. Homer P. Williams, **[*5]** for FPL, and Mr. R. R. Hayes, for FPC, both spoke against that approach. Both Mr. Williams and Mr. Hayes testified that a units of production approach would add an unnecessary complication and would cause the cost per unit to rise over time in the event of unexpected shutdowns. According to both Mr. Williams and Mr. Hayes, estimating a unit's remaining lifetime generation was fraught with uncertainty and could cause unstable cash flow and ratemaking problems.

We find that the present straight line method of accounting for these costs should retained. We direct each company, however, to identify in the cost of service study prepared for its next rate case, all costs that are variable based on production and those that are fixed. This includes investment, depreciation, decommissioning, and operating costs.

Issues 2, 3, 4 and 6

These issues have been rendered moot for the most part.

Issue 5. Decommissioning cost and depreciation expense currently in base rates.

FPL employs a composite rate of 3.2% before decommissioning. To reflect decommissioning, the rate for Account 321, Structures and Improvements, is 3.9%, and the rate for Account 322, Reactor plant Equipment, **[*6]** is 3.8%.

FPC's currently approved depreciation rate for CR3 is 3.6%. The rate applicable to depreciation is 3.23% and the rate applicable to decommissioning is .37%. The Company has requested the approval of a 3.8% depreciation rate based on an updated study of decommissioning costs and has used this rate in its pending rate case.

In ***Order*** No. 10987, we determined that decommissioning costs should be accounted for separately. Based on the information presented at the hearing, we are able to identify the appropriate separation. FPL's composite depreciation rate of 3.75%, which includes a decommissioning accrual, should be reduced to 3.6%, resulting in a reduction in annual depreciation expense of $1,389,693. FPC's composite rate of 3.6% should be reduced to 3.2%, resulting in a reduction in annual depreciation expense of [ILLEGIBLE WORD]

Revised estimates of decommissioning cost were presented at hearing. The total cost for FPL in 1982 dollars is $209,765,026 (excluding St. Lucie No. 2) and for FPC the cost is $79,659,200. The annual expense for FPL in 1982 dollars is $8,561,962 (excluding St. Lucie No. 2) and for FPC is $2,783,641. These annual amounts are simply **[*7]** an average of present value dollars over the remaining life of the plant. The Companies and Staff proposed to adjust the annual accrual each year to reflect the changes in the value of the dollars received. Since future dollars will be of less value due to inflation, under this plan the succeeding annual accruals would be adjusted upward to accumulate the total dollars required. We find that equal annual accruals are more appropriate. This will require that the annual accrual be inflated to reflect the additional dollars related to future inflation. Data to calculate equal annual accruals was not provided at hearing. At the close of the January 13, 1983 hearing we directed the companies to submit, as late filed exhibits, calculations of equal annual accruals. Upon receipt of those calculations we will authorize revised annual accruals.

We anticipate that the revised annual accruals will exceed the current annual amounts identified above. However, we find it appropriate to require the utilities to begin funding the reserve immediately. We therefore direct both FPL and FPC to fund their reserves as of January 1, 1983, and revise their annual accruals to $8,561,962 and $2,783,641, **[*8]** respectively. At such time as final revised accruals are approved, the funding levels shall be likewise adjusted. We will determine at a later date the manner in which rates will be revised to allow collection of the revenue deficiency associated with these newly revised accruals.

Issue 7. Funding Net or Gross of Tax

All parties propose funding of the decommissioning reserves net of tax. We agree. The deduction of decommissioning expense from taxable income at the time of decommissioning, in addition to the funded reserve, should provide sufficient funds to complete decommissioning.

IV. FINAL RULING

A final hearing was scheduled for July 13, 1983. The prehearing ***order*** issued July 8, 1983, (***Order*** No. 12214) identified the issues on which evidence had been received as of the January 13, 1983, hearing but on which we had not ruled. Those issues are:

1. What decommissioning methodologies should be approved for ratemaking purposes for Florida Power Corporation and Florida Power and Light Company?

2. What is the appropriate annual decommissioning expense and funding requirement in equal dollar amounts necessary for each company to recover future decommissioning **[*9]** costs net of tax over the remaining life of each nuclear power plant?

3. What is the additional annual decommissioning revenue requirement for each Company?

Order No. 12214 also identified the following issues that were to be the subject of the July 13, 1983 hearing:

4) When should the Commission revise the rates of Florida Power & Light Company and Florida Power Corporation in ***order*** to allow collection of the additional revenue requirements?

5) What are the appropriate billing determinants and jurisdictional separation factors to be used in this docket for ratemaking purposes?

6) How should the additional annual revenue requirement determined in this docket be allocated to rate classes?

7) How should the additional annual revenue requirement for each class be collected?

8) Should decommissioning costs collected prior to 1983 be funded?

9) How should decommissioning costs collected prior to 1983 be funded?

10) How should each Company recover the difference between the amount accrued in 1983 and the amount currently included in base rates?

Decommissioning Methodology

FPC proposes to decommission its nuclear unit by the immediate dismantlement methodology. **[*10]** FPC's projected decommissioning cost for the unit in 1982 dollars is $79,659,200. FPC's proposed use of immediate dismantlement results in the lowest estimated cost of dismantlement for the company. FPL proposes to decommission its nuclear units by the delayed dismantlement methodology. FPL's projected decommissioning cost in 1982 dollars for its units (excluding St. Lucie No. 2) is $250,662,902 under this methodology. FPL's projected costs under immediate dismantlement, however, is $212,715,026.

Mr. Michael Akins presented testimony in support of FPL's use of a delayed dismantlement methodology. Mr. Akins' reasons for choosing delayed dismantlement were:

1) The resolution of waste disposal is uncertain at this time;

2) Delayed dismantlement results in a substantial reduction in radiation exposure and, if a dollar value is assigned to worker exposure, the cost advantage of immediate dismantlement is partially offset;

2) Large scale dismantlements have not been performed to date and delayed dismantilement will provide an opportunity to learn from experience and take advantage of improved technology.

Although Mr. Akins stated that immediate dismantlement was projected to be **[*11]** the least costly methodology, he did not agree that the least cost alternative was necessarily the best choice. According to Mr. Akins, the cost comparisons did not take into consideration the exposure of workers to radiation during dismantlement. According to Mr. Akins, safety and health are much more important than dollars. Mr. Akins agreed, however, that all dismantlement must be done in accordance with NRC requirements and that the NRC would not knowingly allow a dismantlement process that endangered human life. Mr. Akins, however, took issue with the man-rem value adopted by NRC, asserting that the actual cost could be far greater than the NRC has recognized. According to Mr. Akins, if the dollars per man-rem were as high as some studies had indicated, it would be cost effective to delay dismantlenent. Mr. Akins, however, had no opinion as to the further development [ILLEGIBLE WORD]

Although it is possible to calculate dollars per man-rem for FPL's decommissioning, Mr. Akins performed no such analysis and thus no comparison of cost effectiveness between delayed and immediate dismantlement is available.

In Mr. Akins'opinion, if a disposal site is available, if **[*12]** there is a place to dispose of the fuel, and if the regulatory climate allows for immediate dismantlement, immediate dismantlement would be the methodology he would recommend. Mr. Akins believed that dismantlement in 2008 probably would be easier than at the current time but, at the same time, he could not state that a unit could be dismantled after being mothballed for 30 years. According to Mr. Akins, it might require 100 years.

We view FPL's rationale for choosing delayed dismantlement to be insufficient to justify the additional cost over immediate dismantlement. Though the present value calculations of the costs of immediate dismantlement and delayed dismantlement assume facts clearly subject to change, we believe that the identified cost differential between these two methodologies has a sound basis and can be expected to prevail in the future. On the other hand, the purported benefits of delayed dismantlement are largely speculative and somewhat subjective and do not outweigh the identifiable increased cost associated with delayed dismantlement.

We find, therefore, that we should approve, for rate making purposes only, immediate dismantlement as the appropriate decommissioning **[*13]** methodology for both FPC and FPL. Development of decommissioning accruals for each company will be on that basis.

Revised Annual Decommissioning Accruals

We previously determined that both companies should accrue decommissioning expenses in equal annual amounts. At the time, however, we lacked sufficient information as to the proper annual amount for each company. Though we established interim accrual levels for each company, we directed that they file, as late-filed exhibits, information sufficient to make a final calculation. Both companies have submitted late-filed exhibits containing alternative scenarios as to inflation, fund earnings and decommissioning methodology. Based on those late filed exhibits, as well as testimony of record, we find that the appropriate decommissioning accruals for FPL and FPC are $14,546,711 and $5,356,000, respectively.

FPL and FPC based their annual accrual calculations on computer models utilizing several alternative assumptions. FPL presented seperate calculations for immediate dismantlement and delayed dismantlement. For each of these it assumed fund earnings of 0%, 4.8% and 6% respectively. FPL settled on fund earnings of 4.8%, **[*14]** which is 80% of the assumed inflation rate of 6%. FPC presented calculations for immediate dismantlement only, assumed the fund to earn at a rate equal to inflation and assumed inflation at 6.56%.

We have already determined that we should consider immediate dismantlement as the appropriate methodology for ratemaking purposes. We will therefore limit our review of FPL's accrual calculations to those based on the immediate dismantlement methodology. We find that FPL's assumed inflation rate of 6% is reasonable. We further find that an assumption of fund earnings at a rate equal to inflation is reasonable. According to the alternative calculations provided by each company, those assumptions lead to the revised annual accruals stated above.

Since we have decided to revise each company's rates as of October 1, 1983, each company shall revise its accruals and funding to the approved levels effective October 1, 1983.

<u>Funding of decommissioning costs collected prior to 1983.</u>

All parties agree that decommissioning costs collected prior to 1983 should be included in the fund. They do not agree as to how the funding is to occur.

FPL and Public Counsel propose that the **[*15]** funding occur in conjunction with each company's next rate case. FPC and staff propose that the pre-1983 collections be funded net of taxes. We agree with FPC and staff. There is no compelling reason to further delay the accurate accrual of decommissioning costs and ignore the responsibility of current ratepayers for the benefit of service currently received. We also agree that the pre-1983 collection should be funded net of tax, as that was the basis on which they were collected.

<u>Additional Revenue Requirement</u>

Approval of revised decommissioning accruals and funding requirements for each company creates an additional expense and a revenue deficiency for each company. FPC's base rates currently recover $2,260,608 per year in decommissioning expense. The newly approved annual decommissioning accrual of $4,349,072 exceeds this amount by $2,088,464. Applying the appropriate revenue expansion factor (limited to gross receipts tax and regulatory assessment fee) to this additional expense, FPC's additional jurisdictional revenue requirement over current base rates is $2,122,000 per year.

FPL's base rates currently recover $1,199,080 per year in decommissioning expense (excluding **[*16]** St. Lucie No. 2). The newly approved annual decommissioning accrual of $13,478,255 (also excluding St. Lucie No. 2) exceeds this amount by $12,279,175. Applying the appropriate revenue expansion factor to this additional expense, FPC's jurisdictional revenue requirement over base rates is $12,474,046 per year.

<u>Timing of Changes in Rates</u>

a. <u>Changes to recognize additional expense incurred as of October 1, 1983.</u>

In ***<u>Order</u>*** No. 10987, we had determined that we would not delay changing the utilities' rates to recognize additional decommissioning expense until their next rate cases. Since that time, each company has completed a full revenue requirements case.

Public Counsel proposes that we not change the utilities' rates to recognize additional decommissioning expense until their next rate cases. FPC and the staff propose that rates be changed immediately. FPL proposes that the changes be delayed until its next rate case to allow recognition of certain rate base changes that occur when the reserve for accumulated depreciation is reduced due to separating out the decommissioning reserve.

We intend to adhere to our earlier finding in ***<u>Order</u>*** No. 10987. Continuing rates **[*17]** at their current level simply exacerbates the inequity involved in allowing current customers to share in the benefits of nuclear power without bearing their fair share of the costs. We have already decided that the companies should begin accruing decommissioning expense as of January 1, 1983, via a funded reserve. Further delay in recognizing the fairness of charging current customers for the current cost of the service they receive is not justified.

We do not agree, however, that rates should be changed immediately. In the next paragraph we will discuss the availability of a mechanism similar to the fuel adjustment to recover the revenue deficiency associated with the interim accrual. We frind that revisions of each company's rates to recognize the additional revenue requirement associated with the final accrual for each Company should coincide with the October 1, 1983 fuel adjustment. This adjustment factor will continue until each company's base rates are revised in a rate case.

b. Changes to recover additional expense incurred as of January 1, 1983

In our January 13, 1983 ruling, we required each company to begin funding its decommissioning reserve, net **[*18]** of tax, and revise its accrual at interim levels above those then recognized in base rates. This necessarily required the companies to incur expenses at levels higher than recognized in their rates. FPC's interim revenue deficiency ceased as of February, 1983, when we authorized a revision to its base rates that encompassed the additional revenue requirement. FPC's total jurisdictional interim revenue deficiency is $186,816. FPL, however, will continue to incur a revenue deficiency until its rates are revised to recover the higher decommissioning expense. As we will permit each company to apply an adjustment factor beginning October 1, 1983, FPL's revenue deficiency will continue through the end of September.

When we required each company to begin the interim funding and revise its accrual we determined that we would revisit the issue of revenue requirements to allow the companies to recover the revenues related to that unrecovered expense. The staff has proposed that we utilize a mechanism in conjunction with the fuel adjustment to allow recovery of this expense. Public Counsel proposes that the revenue deficiency be recognized in each company's next rate case and amortized **[*19]** over an appropriate period. We agree with staff. We required the companies to change their accounting for decommission expense as of January 1, 1983, with the knowledge that a revenue deficiency would thereafter be generated. The companies should not be required to bear the cost of the resulting revenue deficiency until their next rate case.

The companies should be allowed to apply, through a mechanism in conjunction with the fuel adjustment, a charge designed to recover the revenue deficiency associated with accruing the new decommission expense as of January 1, 1983. The factor will apply during the October, 1983 through March, 1984 period. It will not apply thereafter.

Jurisdictional Separations Factors and Billing Determinants

Having determined that rates should be changed to recover additional revenue requirements, we must determine the manner in which those rates are to be changed.

The parties have agreed that, if rates are changed, the following billing determinants and jurisdictional separations factors should be used:

For FPC: those used in Docket No. 820100-EU;

For FPL: the 1982 jurisdictional separation factor used in Docket No. 820097-EU **[*20]** should be used, while the 1983 billing determinants used for the St. Lucie No. 2 proceeding should be used.

We agree with the parties' choice of jurisdictional separation factors for each company. We also agree with the choice of demand allocators. We do not, however, agree that the agreed-upon kwh consumption should be used. The fuel adjustment mechanism relies upon current projections of kwh for the period. The current level of kwh sales should be used for the decommissioning "adjustment," rather than the old projections used in the last rate cases. Current projections of kwh sales by class for the next year are more reliable than past projections. The only distinction between the kwh projections used for fuel adjustment purposes and for decommissioning purposes is that the projections for fuel adjustment do not separate kwh by class and are only for a six-month period. KWH projections for decommissioning purposes, however, should be separated by class and be projected for a full year.

Allocation Among Rate Classes

Having identified the appropriate basis for allocating revenue responsibility, we must next determine the manner in which the additional revenue requirement **[*21]** is to be allocated among the individual rate classes.

FPL and Public Counsel propose that the revenue requirement be allocated by dividing the dollar amount of the revenue increase by the sum of the demand and energy base revenues of the appropriate test period. FIPUG, FPC and the staff propose to allocate the revenue requirement on the basis of the production demand allocation factor used in each utility's most recent rate case.

We agree with FIPUG, FPC and staff. The appropriate allocation of decommissioning costs between classes is on the basis of production demand. This is the normal basis of allocating decommissioning costs within a rate case. FPL points to our recent decision in its St. Lucie No. 2 case as support for its position. The allocation between energy and demand in FPL's St. Lucie No. 2 proceeding was not based solely on the fact that a new plant was going into service but included considerations of fuel savings as well. Costs were allocated to energy partially on the basis of projected fuel savings from that particular plant.

<u>Manner of collection within rate classes.</u>

Having determined the basis for allocating the additional revenue requirement among **[*22]** rate classes, we must now determine the basis for collecting the revenue within each class.

FPL and Public Counsel propose that the revenue be collected within each class by applying a percentage adder to the individual demand and energy charges within each class. FIPUG proposes that where a demand charge is collected, the entire increase should be placed on the demand charge. FPC and staff propose that the entire increase be collected on the energy charge.

We agree with FPC and staff. We have already required that the kwh billing determinants to be used in this proceeding should be projected for the next twelve month period. As we noted earlier, this data is already available in the fuel adjustment proceeding. However, the kw billing determinants are not used in the fuel adjustment proceeding and are not readily available.

FIPUG's assertion that the revenue increase should be included on demand charges because the currently approved demand charges are below unit cost is misplaced. First, the unit costs identified by each company's last cost of service study were based on each company's proposed revenue increase. They reflected each company's proposed rate base **[*23]** and return on investment. Since we set the rate base and rate of return in each case below the levels proposed by each company, the approved demand charges would necessarily fall below the unit cost shown in the cost of service studies. Secondly, the accuracy of the load research that stood as the basis for FPL's and FPC's last cost-of-service studies was not of such quality that the indicated unit costs for kw demand are necessarily correct. In both FPL's and FPC's most recent rate cases we commented on the unsatisfactory quality of their load research.

V. <u>CONCLUSIONS OF LAW</u>

Based on the foregoing, we ***<u>conclude</u>*** as follows:

(1) Florida Power and Light Company and Florida Power Corporation are currently accruing insufficient amounts to adequately provide for the decommissioning of their nuclear powered generators.

(2) The appropriate annual decommissioning accrual, on a jurisdictional basis, is $13,478,255 for Florida Power & Light Company and $4,349,079 for Florida Power Corporation.

(3) Each Company shall revise its annual accrual to these levels as of October 1, 1983, and fund its decommissioning reserve, net of taxes, accordingly. The fund shall include all decommissioning **[*24]** expense collected prior to 1983, net of tax.

(4) The appropriate additional annual revenue requirement sufficient to permit each company to recover its additional expense associated with the above revision to its accrual and funding of its reserve is $12,474,046 for Florida Power & Light Company and $2,122,000 for Florida Power Corporation.

(5) Revision of the rates of each company to recover this additional revenue requirement is necessary to correct rates which are unjust, unreasonable, insufficient and unjustly discriminatory. Such revision should occur as soon as reasonably necessary. Each company is authorized to apply an adjustment factor to its customers' bills, as of October 1, 1983, until such time as its base rates are revised to recover this additional revenue requirement. The adjustment factor shall be determined in accordance with this ***order***.

(6) Each company has incurred a revenue deficiency, as of January 1, 1983, due to the requirement to begin funding its decommissioning reserve as of that date and the requirement to revise its decommissioning accrual upwards. We deferred recovery of this deficiency until a later date. Each company should recover its deficiency **[*25]** via a one time adjustment factor calculated in accordance with this ***order***, to be effective October 1, 1983, through March 31, 1984. The revenue deficiency for Florida Power Corporation is $186,733. The revenue deficiency for Florida Power & Light Company shall be determined in conjunction with the August fuel adjustment hearings.

(7) Determination of the appropriate decommissioning adjustment factors will be made in conjunction with upcoming hearings on the fuel adjustment.

Based on the foregoing,

It is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company and Florida Power Corporation shall, effective October 1, 1983, revise their annual nuclear decommissioning accruals to the levels identified in this ***order***. It is further

ORDERED that each utility continue to fund its decommissioning accrual, including the decommissioning reserve as of December 31, 1983, net of tax, and revise its fund in conjunction with the revision of its accrual. It is further

ORDERED that each company may recover the revenue deficiency associated with the October 1, 1983 revision to its accrual through adjustment factors to be calculated in accordance with this **[*26]** ***order*** beginning October 1, 1983, until each company's next rate case. It is further

ORDERED that each company may recover the revenue deficiency associated with funding its reserve and revising its annual accrual as of January 1, 1983, through adjustment factors to be calculated in accordance with this ***order*** from October 1, 1983, through March 31, 1984. It is further

ORDERED that the adjustment factors authorized herein are to be specifically approved in conjunction with the August, 1983 fuel adjustment proceedings.

By ***Order*** of the Florida Public Service Commission this 12th day of August, 1983.

FL Public Service Commission Decisions

End of Document

[1983 Fla. PUC LEXIS 170](#)

Florida Public Service Commission

November 3, 1983

DOCKET NO. 820545-TP; ORDER NO. 12654, 83 FPSC 45

FL Public Service Commission Decisions

Reporter
1983 Fla. PUC LEXIS 170 *

In re: Application of CENTRAL TELEPHONE COMPANY for new depreciation rates

Core Terms

depreciate, amortize, salvage, retirement

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, KATIE NICHOLS, SUSAN LEISNER

Opinion

NOTICE OF PROPOSED AGENCY ACTION REGARDING THE APPROVAL OF NEW DEPRECIATION RATES

BY THE COMMISSION:

Central Telephone Company of Florida (Centel or Company) has filed for changes in its depreciation rates to be effective as of January 1, 1983. Centel last applied for a comprehensive review of life and salvage factors in 1979 at which time a revision in current whole life rates was prescribed. Subsequently in 1981, a partial represcription covering central office equipment (electromechanical switching) and large PBX's was made at which time these accounts were given remaining life rates. Later, in 1982, this Commission authorized a capital recovery schedule for the unrecovered investment associated with the Florida state centrex system. The current request for an overall review of life and salvage factors was filed pursuant to Florida Administrative Code Rule 25-4.175(7) which requires an overall review every three years.

After a review of the record, we make the following findings:

1. New depreciation rates **[*2]** should be precribed for Central Telephone Company as of January 1, 1983.

2. Centel has a net reserve deficit of $21.2 million of which $9.1 million is a historic deficit which is the result of growth, technological change, and basic incorrect estimates of property life and salvage. We think this balance should be amortized over a five-year period. The remaining $12.1 million is a prospective deficit due to changes in estimated life and salvage components now considered appropriate for the plant now serving the public. This portion should be amortized over the remaining life of the plant which is thirteen (13) years.

3. The $1.6 million of Private Line Services investment that Centel had included in Account 231.2 (Official Telephones) should be carried in a separate sub-account and dealt with in the deregulation docket. The applicable

ATTACHMENT B

depreciation rate for this investment is ten percent (10%) based on a remaining life of 4.7 years, a net salvage of zero percent (0%), and a reserve of fifty-three percent (53%) as of January 1, 1983.

4. The projected additions for these electromechanical offices which are planned for retirement during the 1983-1985 time period should be classified **[*3]** to the digital account and booked as incurred to that account.

5. Centel's policy to replace analog circuit equipment with digital circuit equipment is considered prudent.

6. The retirement by Centel of its electromechanical central office equipment is considered justified.

7. The depreciation rates and recovery schedules shown on Attachment I to this order are just and reasonable and should be approved.

Incorporated in the approved depreciation rates are certain recovery schedules designed to recover net deficits existing as of 1/1/83. <u>It should be noted that the associated expenses and amortization period were approved, not a rate to be applied to surviving investments.</u> These schedules are as follows:

State Centrex - Monthly expense of $85,698 for the eight months January through August, 1983.

Monthly expense of $54,269 for the four months September through December, 1983.

December, 1983 is the final month for this schedule.

C.O.E. Manual - Monthly expense of $59,041 beginning January 1, 1983 and ending December 31, 1983.

Aerial Wire - Monthly expense of $2,490 beginning January 1, 1983 and ending December 31, 1983.

C.O.E. Crossbar 1983-1985 Retirements **[*4]** - Monthly expense of $7,020 beginning January 1, 1983 and ending December 31, 1985.

C.O.E. Step 1983-1985 Retirements - Monthly expense of $185,541 beginning January 1, 1983 and ending December 31, 1987.

It is, therefore,

ORDERED by the Florida Public Service Commission, that each and every finding set out in the body of this order and the depreciation rates and recovery schedules shown on Attachment I are approved and may be implemented as of January 1, 1983. It is further

ORDERED that Central Telephone Company will submit quarterly reports to this Commission's Auditing and Financial Analysis Department beginning January 1, 1984 for the step by step and crossbar C.O.E. recovery schedules showing plant balances and activity and reserve balances and activity. These reports should also list any changes in plans such as retirement dates or anticipated net salvage. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final agency action unless a person adversely affected by the action taken herein files a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29(4), that must be received by the **[*5]** Commission Clerk by the close of business on November 24, 1983, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this Order shall become effective and final, as provided by Florida Administrative Code Rule 25-22.29(6), and as reflected in a subsequent order.

By Order of the Florida Public Service Commission, this 3rd day of November, 1983.

<u>ATTACHMENT I</u>

CENTEL TELEPHONE COMPANY

Authorized of Depreciation Rates and Components

Acct.#	Description	**Average Remaining Life (years)**	**Future Net Salvage (%)**	**Appropriate Reserve (%)** *	**Remaining Life (%)**
211	Buildings	28	(3)	24.6	2.8
221.1	COE Step (Remainder)	7.4	(3)	54.16	6.6
221.3	COE Radio	9.1	(2)	41.03	6.7
221.4	COE Circuit-Other	3.8	0	64.66	9.3
221.5	COE Crossbar (Remainder)	4.4	0	61.72	8.7
221.6	COE Circuit-Digital	11.2	15	21.16	5.7
221.8	COE Electronic-Analog	16.5	2	17.15	4.9
221.9	COE Electronic-Digital	17.7	5	10.04	4.8
231.1	Embedded CPE	4.5	20	42.65	8.3
231.2	Official Telephones	4.7	0	53.0	10.0
231.2	Private Line Services	4.7	0	53.0	10.0
231.3	Pay Stations	4.7	0	53.0	10.0
231.5	Deaf	4.9	0	51.0	10.0
232.2	Drop Wire				5.0
234.1	Embedded PBX	3.2	5	19.43	23.6
234.2	Official PBX	4.5	0	50.05	11.1
241	Pole Lines	16.9	(51)	34.39	6.9
242.1	Aerial Cable	16.6	(20)	33.68	5.2
242.2	Underground Cable	27	(8)	24.3	3.1
242.3	Buried Cable	16.7	(3)	24.51	4.7
242.4	Submarine Cable	15.3	0	38.8	4.0
244	Underground Conduit	43	0	22.6	1.8
261	Furniture/Office Equipment	16.1	1	18.5	5.0
	Computers	4.0	0	60.0	10.0
264.1	Vehicles				
	Cars	3.3	18	36.79	13.7
	Light Trucks	3.5	18	41.05	11.7
	Heavy Trucks	7.3	18	27.25	7.5
264.2	Other Work Equipment	11.3	2	29.07	6.1

[*6]

Recovery Schedules:

* Appropriate Reserve (except for embedded CPE and PBX) denotes Staff calculated theoretical reserve.

ATTACHMENT B

221.1	Step (83-85 Rets.)	5 YEAR AMORTIZATION
221.2	COE Manual	1 YEAR AMORTIZATION
221.5	Crossbar (83-85 Rets.)	3 YEAR AMORTIZATION
243	Aerial Wire	1 YEAR AMORTIZATION
	State Centrex	1 YEAR AMORTIZATION

Melinda Marzicola **ATTACHMENT B**

[1984 Fla. PUC LEXIS 959](#)

Florida Public Service Commission

January 10, 1984

DOCKET NO. 830370-TP; ORDER NO. 12857, 84 FPSC 140

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 959 *

In re: Application of United Telephone Company of Florida for new depreciation rates

Core Terms

depreciate, deficit, cable, embed, plant, amortize, retire, switch, composite, salvage, manual, wire

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS, SUSAN W. LEISNER

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER GRANTING NEW DEPRECIATION RATES

BY THE COMMISSION:

This matter was initiated upon the request of United Telephone Company of Florida (United) for new depreciation rates. The request reflects the merger of Florida Telephone Corporation, United Telephone Company of Florida, Winter Park Telephone Company and Orange City Telephone Company, Inc. which was effective December 31, 1982. Each of these companies prior to merger had their own separate depreciation rates. Net plant balances, composite ages and lives have changed due to the merger, in addition to technological impacts on life and salvage. These changes indicate a need for review and revised rates where appropriate.

We have reviewed the requested changes and the supporting data for the enumerated accounts and find that the depreciation rates and capital recovery schedules, effective January 1, 1983, as shown on Appendices A and C to this Order and incorporated herein, are approved.

I. Appropriate **[*2]** Depreciation Reserve Level and Correction of the Reserve Deficit.

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current booked reserve levels and what the reserve levels would have been if the new depreciation rates had been in effect. We have calculated the net reserve deficit to be $36,120,000 on a composite basis. [1] White it is possible to make that correction through the new depreciation rates allowed for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the company to separately recover the reserve deficit, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

We are ordering two amortization schedules for use in recovering the reserve **[*3]** deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant, which is estimated to be 13 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 13-year period is $3,685,000, and the amount to be amortized over a 5-year period is $32,435,000. This results in annual expenses of $283,462 and $6,487,000, respectively.

The Company is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amoritization of the two deficit amounts. No further deficits should be included in these accounts without Commission approval. Likewise, each depreciable account's reserve should be restated to the level shown in Appendix B to this Order, which is incorporated herein, and brought forward from that point. The book reserve total is not changed by the setting **[*4]** of the reserve imbalance and restatement of the account reserves. These reserve levels should be shown on Company books or side records as of January 1, 1983, and brought forward from that time by account activity. These reserves should be shown in the Company's next depreciation study, updated to the implementation date of the new rates proposed in that study.

II. Recovery Schedule For Retiring Switches

We have not included in the reserve deficit calculation the reserve relating to the investment in electromechanical switches retiring during the 1983-1985 period. The unrecovered investment in those switches, as of January 1, 1983, is $38,494,806. This investment includes the merger of the existing three recovery schedules. For this amount, we are ordering a capital recovery schedule for a three-year period beginning January 1, 1983. Annual expense for this recovery schedule is $12,831,602.

United anticipates making gross additions to some of the electromechanical switches discussed above which are scheduled for retirement in 1983, 1984 and 1985. Such short-lived additions are necessary because of the need to have capacity to provide service as requested by customers **[*5]** in these offices and will be retired with their associated switches. We, therefore, recognize the need for a new policy approach regarding recovery treatment of these additions. The affected offices that are on the recovery schedule are:

Manual

Ocala	Fort Myers
Leesburg	Winter Garden
Avon Park	

Step-by-Step

Boca Grande	Pine Island
North Naples	Silver Springs
Mt. Dora	

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[1] This deficit does not include investment associated with electromechanical switches scheduled for retirement in 1983-1985, embedded CPE accounts (Account Nos. 231.1 and 234.1), and the drop wire portion of station connections (Account 232.9).

Crossbar

Punta Gorda	Inverness
Ocala-Toll	East Fort Myers
Bonita Springs	Fort Myers-Toll
Alva	Lake Helen
Leesburg-Local	Dade City
Winter Garden-Toll	Avon Park-Toll
Leesburg-Toll	

Automatic Message Recording

Pine Island	Punta Gorda
Inverness	Ocala
Silver Springs	East Fort Myers
Bonita Springs	Fort Myers
Alva	North Naples
Lake Helen	Mt. Dora
Avon Park	Dade City
Leesburg	Winer Garden

The purpose is to recover these added investments by the time of the next study (three years), by which time the retirement activity will have been booked and the true-up can be made. We find it appropriate, therefore, to apply the rates shown on Appendix C, which are incorporated herein, to these short-lived additions. If any additions are subsequently judged imprudent, the related **[*6]** recovery expenses can be disallowed in rate case proceedings.

Quarterly reports beginning January 1, 1984 showing plant and reserve balances and activity, as well as any changes in plant, or in anticipated net salvage for these installations are required and should be submitted to the Auditing and Financial Analysis Department.

This docket will be closed unless an appropriate petition for hearing is filed by one whose substantial interests may or will be affected by this proposed agency action, as provided by Florida Administrative Code Rule 25-22.29. It is, therefore,

ORDERED by the Florida Public Service Commission that the depreciation rates and amortization schedules as set forth in the body of this Order be and hereby are approved for United Telephone Company of Florida, Inc. effective January 1, 1983. It is further

ORDERED that the Company shall submit reports as set forth in the body of this Order. It is further

ORDERED that the provisions of this Order, issued a proposed agency action, shall become final agency action unless a person adversely affected by the action taken herein files a petition for a formal proceeding, as provided by Florida Administrative Code Rule **[*7]** 25-22.29(4), that must be received by the Commission Clerk by the close of business on January 31, 1984, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this Order shall become effective and final, as provided by Florida Administrative Code Rule 25-22.29(6), and as reflected in a subsequent Order.

By ORDER of the Florida Public Service Commission, this 10th day of January, 1984.

Melinda Marzicola

ATTACHMENT B

APPENDIX A

UNITED TELEPHONE COMPANY OF FLORIDA

Depreciation Rates and Components (1983 Study)

		APPROVED RATES			
Account		**Average Remaining Life** (years)	**Future Net Salvage** (%)	**Appropriate Reserve** * (%)	**Remaining Life Rate** (%)
212.10	Buildings	32	0	20.0	2.5
212.20	Towers	16.8	0	37.84	3.7
212.50	Building Equipment	15.3	0	3.61	6.3
221.10	Manual (Remaining)	7.5	0	33.25	8.9
221.30	Step (Remaining)	5.5	8.5	46.4	8.2
221.40	Crossbar (Remaining)	6.2	3.4	48.86	7.7
221.50	Circuit	8.5	5	34.65	7.1
221.60	Radio	8.8	0	32.24	7.7
221.70	Mobile Radio	8.8	0	32.24	7.7
221.80	Electronic	13.6	(5)	17.96	6.4
221.90	AMR (Remaining)	5.6	0	51.84	8.6
231.1	Embedded CPE	4.2	20	30.14	11.9
231.2	Official Telephones	4.4	0	37.08	14.3
231.7	Subscriber Multiplex	6.5	0	7.05	14.3
231.8	Paystations	5.4	0	32.5	12.5
232.9	Drop Wire				5.0
234.1	Embedded PBX	4.3	5	26.25	16.0
234.2	Official PBX	5.1	0	27.07	14.3
241.00	Pole Lines	15.7	(45)	33.53	7.1
242.10	Aerial Cable	13.4	(15)	26.56	6.6
242.20	Underground Cable	29	(5)	18.0	3.0
242.30	Buried Cable	17.8	(5)	19.56	4.8
242.40	Submarine Cable	18.2	0	27.2	4.0
243.00	Aerial Wire	8.1	(25)	52.1	9.0
244.00	Underground Conduit	43	0	14.0	2.0
261.12	Furniture	13.2	5	26.36	5.2
261.22	Office Equipment	7	0	25.1	10.7
261.31	Data Processing	3.7	0	38.21	16.7
264.11	Cars	3.3	16	37.8	14.0

* Denotes calculated theoretical reserve except for Accounts 231.1, 234.1, and 232.9

UNITED TELEPHONE COMPANY OF FLORIDA

Depreciation Rates and Components (1983 Study)

		APPROVED RATES			
Account		**Average Remaining Life**	**Future Net Salvage**	**Appropriate Reserve** *	**Remaining Life Rate**
264.12	Light Trucks	3.5	18	34.05	13.7
264.13	Heavy Trucks	8.1	18	15.58	8.2
264.14	Special Purpose Vehicles	7.2	10	25.2	9.0
264.20	Other Work Equipment	10.6	0	28.98	6.7

Recovery Schedules:

Manual (1983-1983 Rets)

Step (1983-1985 Rets)

Crossbar (1983-1985 Rets)

AMR (1983-1985 Rets)

Existing Recovery Schedules: 3 year recovery schedule

Ocala (Order 11406)

Step (Order 11458)

Crossbar (Order 11458)

[*8]

APPENDIX B

UNITED TELEPHONE COMPANY OF FLORIDA

1983 Study

Analysis of Reserve Position

Account		**1-1-83 Restated Reserve by Account to be Brought Forward by Annual Activity**
212.10	Buildings	13,440
212.20	Towers	732
212.50	Building Equipment	126
221.10	Manual (Remaining)	454
221.30	Step (Remaining)	9,000
221.40	Crossbar (Remaining)	63,227

UNITED TELEPHONE COMPANY OF FLORIDA

1983 Study

Analysis of Reserve Position

Account		**1-1-83 Restated Reserve by Account to be Brought Forward by Annual Activity**
221.50	Circuit	38,371
221.60	Radio	3,884
221.70	Mobile Radio	260
221.80	Electronic	11,252
221.90	AMR (Remaining)	1,810
231.1	Embedded CPE	* 19,439
231.2	Official Telephones	914
231.7	Subscriber Multiplex	55
231.8	Paystations	2,139
232.9	Drop Wire	* 2,300
234.1	Embedded PBX	* 5,345
234.2	Official PBX	644
241.00	Pole Lines	4,010
242.10	Aerial Cable	11,576
242.20	Underground Cable	12,541
242.30	Buried Cable	59,501
242.40	Submarine Cable	239
243.00	Aerial Wire	2,800
244.00	Underground Conduit	7,129
261.12	Furniture	1,498
261.22	Office Equipment	481
261.31	Data Processing	2,102
264.11	Cars	779
264.12	Light Trucks	2,819
264.13	Heavy Trucks	180
264.14	Special Purpose Vehicles	63
264.20	Other Work Equipment	1,617
Recovery Schedules:		
Manual (1983-1983 Rets)		* 2,839

* Designates reserves associated with investments expected to be deregulated or with investments for which recovery schedules have been recommended. These reserves, therefore, were not included in calculating the bottom line net deficit.

UNITED TELEPHONE COMPANY OF FLORIDA

1983 Study

Analysis of Reserve Position

Account	1-1-83 Restated Reserve by Account to be Brought Forward by Annual Activity
Step (1983-1985 Rets)	* 1,377
Crossbar (1983-1985 Rets)	* 14,442
AMR (1983-1985 Rets)	* 1,968
Existing Recovery Schedules:	
Ocala (Order 11406)	* 986
Step (Order 11458)	* (556)
Crossbar (Order 11458)	* 8,996

[*9]

APPENDIX C

Depreciation Rates For

Short-Lived Electromechanical Additions

	Estimated Additions ($000)	Remaining Life (years)	Depreciation Rate (%)
1983	$ 903.5	1.8	55.6
1984	887.6	1.3	76.9
1985	172.9	0.5	200
	$1,964.0		

The remaining lives listed above are composites of the lives of each addition. (The dollars added at each location multiplied by the remaining life of that location).

Florida Public Service Commission

January 12, 1984

DOCKET NO. 820477-TP; ORDER NO. 12864, 84 FPSC 171

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 943 *

In re: Petition of NORTH FLORIDA TELEPHONE COMPANY for revision of depreciation rates and implementation of Remaining Life

Core Terms

deficit, depreciate, salvage, amortize, tower, embed, central office, carrier, aerial, cable, retirement, plant

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS, SUSAN W. LEISNER

Opinion

NOTICE OF PROPOSED AGENCY ACTION REGARDING THE APPROVAL OF NEW DEPRECIATION RATES

BY THE COMMISSION:

North Florida Telephone Company (North Florida or Company) has filed for changes in its depreciation rates to be effective as of July 1, 1983. North Florida last applied for a comprehensive review of life and salvage factors in 1979 at which time whole life rates were prescribed, effective January 1, 1980. Also, depreciation rates for the Live Oak Toll Center were approved effective January 1, 1982. The current request for an overall review of life and salvage factors was filed pursuant to Florida Administrative Code Rule 25-4.175(7) which requires an overall review every three years. Additionally the Company has asked that the new rates be determined using the Remaining Life Method instead of the Average Service Life of Whole Life Method used in the past.

After reviewing the record, we make the following findings:

(1) New depreciation rates should be prescribed for North Florida as of July **[*2]** 1, 1983.

(2) As we have done with other telephone companies, we approve the use of the Remaining Life Method.

(3) North Florida has a net reserve deficit of approximately $4.3 million, composed of a historic deficit of $3.7 million and a prospective deficit of $0.6 million. The historic deficit is the difference between the book reserve and the reserve that should have accumulated under the rates being prescribed. This historic deficit is brought about by such things as technological change, growth, and incorrect estimates of life and salvage. The prospective deficit is due to the difference between the life and salvage factors we now find appropriate and the previous life and salvage factors. This prospective deficit is generally due to the replacement of older technologies and is based on retirements that are expected to occur in the future.

ATTACHMENT B

(4) With two exceptions, we find that the Company's projected retirement dates for its sixteen electromechanical central offices are reasonable. For the Alachua and Brooker central offices, the Company's projected retirement date is 1987. However, the Company's economic studies showed that the most economic date to retire **[*3]** the Alachua central office is 1989 and to retire the Brooker central office is 1992; therefore, we have used those dates instead of 1987 as the Company projected.

(5) Since there are no electromechanical central offices to be replaced in 1983, 1984 and 1985, no special recovery treatment is needed for central office equipment additions in these years.

(6) We have reviewed the status of the current recovery schedule for the Live Oak Toll switch and find it to be on schedule. The Company expected to cut over to the new equipment in November, 1983 and to have the old equipment off its books by December 31, 1983. The estimated net salvage is 0.

(7) The depreciation rates and recovery schedules shown on Attachment I to this Order are just and reasonable and should be approved.

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current reserve levels and what the reserve levels should be using the new depreciation rates. As discussed previously, we have calculated the net reserve deficit to be $4,329,297 on a composite basis. While it is possible to make that correction through the new depreciation **[*4]** rates allowed for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the Company to separtely recover the reserve deficit, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant, which is estimated to be 13 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 13-year period is $608,002, and the amount to be amortized over a 5-year period is $3,721,295. This results in annual expenses of $46,769 and $744,259 respectively.

The company is to create two separate **[*5]** subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the two deficit amounts. No further deficits should be included in these accounts without Commission approval. Likewise, each depreciable account's book reserve should be restated to the level indicates below and brought forward from that point. The book reserve total of $20,810,506 as of July 1, 1983 is not changed by the restatement of account reserves and the netting of the reserve deficits.

The restated reserve levels by account are shown below. These reserve levels should be shown on Company books or side records as of July 1, 1983, and brought forward from that time by account activity. This reserve should be shown in the Company's next depreciation study, updated to the implementation date of the new rates proposed in that study.

	Account	**7-1-83 Restated Reserve By Account To Be Brought Forward By Annual Activity**
212.2	Service Center	
212.3	Foundations - S.S. Towers	
212.4	Towers - Self Supporting	

	Account	7-1-83 Restated Reserve By Account To Be Brought Forward By Annual Activity
212	Building TOTALS	$986,238
221.1	Trunk Carrier	2,925,313
221.2	Microwave	298,290
221.X	Fiber Optic Carrier	
221.4	Subscriber Carrier	164,810
221.5	Step	1,183,210
221.6	X Bar	3,822,459
221.7	Electronic	478,196
221.8	Digital	887,385
231.1	Embedded Subscriber Equipment	* 3,025,541
231.2	Official Terminal Equipment	12,827
231.3	Pay Stations and Booth	158,813
232.1	Station Connections - Drop	* 516,623
234.1	Embedded Large PBX	* 383,054
234.2	Official PBX	18,857
241.4	Anchors and Guys	
241.6	Towers - Guyed	
241.7	Guyed Tower Foundations	
241	Pole Lines TOTALS	390,055
242.1	Aerial Cable	1,710,323
242.15	Aerial Fiber	
242.2	Underground Cable	106,764
242.3	Buried Cable	7,175,275
242.35	Buried Fiber	
243.0	Aerial Wire	75,772
244.0	Underground Conduit	59,792
261.1	Furniture	53,424
261.3	Office Machines	36,807
264.1	Vehicles	336,576
264.2	Tools and Other Work Equipment	333,399

[*6]

* Book Reserve

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that each and every finding set out in the body of this Order and the depreciation rates and recovery schedules shown on Attachment I are approved and may be implemented as of July 1, 1983. It is further

ORDERED that the Company create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the historic and prospective deficit as set out in the body of this Order. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final agency action unless a person adversely affected by the action taken herein files a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29(4),that must be received by the Commission Clerk by the close of business on January 27, 1984, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this Order shall become effective and final, as provided by Florida Administrative Code Rule 25-22.29(6), and as reflected in a subsequent order. **[*7]**

BY ORDER of the Florida Public Service Commission, this 12th day of JANUARY, 1984.

ATTACHMENT I

NORTH FLORIDA TELEPHONE COMPANY

AUTHORIZED DEPRECIATION RATES AND COMPONENTS

Acct.#	**Description**	**Average Remaining Life (Years)**	**Future Net Salvage (%)**	**Appropriate Reserve (%)**	**Pemaining Life Pate (%)**
212.2	Service Center				
212.3	Foundations - S.S. Towers				
212.4	Towers Self Supporting				
212	Buildings TOTALS	28.3	2.0	28.6	2.5
221.1	Trunk Carrier	6.8	6	44.8	7.2
221.2	Microwave	7.7	0	48.7	6.7
221.X	Fiber Optic Carrier	10.0	0	0.0	10.0
221.4	Subscriber Carrier	8.5	6	14.0	9.4
221.5	Step	4.5	0	55.0	10.0
221.6	X Bar	6.2	4	44.2	44.2
8.4					
221.7	Electronic	?5.9	0	59.0	7.0
221.8	Digital	15.6	0	13.3	5.6
231.1	Embedded Subscriber Equipment	4.5	20	40.0	8.9

NORTH FLORIDA TELEPHONE COMPANY

AUTHORIZED DEPRECIATION RATES AND COMPONENTS

Acct.#	**Description**	**Average Remaining Life (Years)**	**Future Net Salvage (%)**	**Appropriate Reserve (%)**	**Pemaining Life Pate (%)**
231.2	Official Terminal Equipment	8.0	2.0	26.8	8.9
231.3	Pay Stations and Booths	8.6	2.0	27.8	8.2
232.1	Station Connections - Drop				5.0
234.1	Embedded Large PBX	4.5	6	46.5	10.6
234.2	Official PBX	4.0	0	50.0	12.5
241.4	Anchors and Guys				
241.6	Towers - Guyed				
241.7	Guyed Tower Foundation				
241	Pole Line TOTALS	13.5	-35	43.9	6.7
242.1	Aerial Cable	13.6	-25	40.0	6.3
242.2	Underground Cable	26.3	4	17.1	3.0
242.3	Buried Cable	19.6	0	21.6	4.0
242.15	Aerial Fiber	20.0	- 5	0.0	5.3
242.35	Buried Fiber	20.0	- 5	0.0	5.3
243.0	Aerial Wire	7.2	-25	35.0	12.5
244.0	Underground Conduit	39.6	0	20.8	2.0
261.1	Furniture	13.9	5	28.9	4.8
261.3	Office Machines	5.1	5	46.5	9.5
264.1	Vehicles	4.3	17	32.0	11.9
264.2	Tools and Other Work Equipment	10.3	5	33.8	5.9

[*8]

FL Public Service Commission Decisions

End of Document

Melinda Marzicola

ATTACHMENT B

1984 Fla. PUC LEXIS 945

Florida Public Service Commission

January 12, 1984

DOCKET NO. 830268-TP; ORDER NO. 12866, 84 FPSC 177

FL Public Service Commission Decisions

Reporter

1984 Fla. PUC LEXIS 945 *

In re: Petition of INDIANTOWN TELEPHONE SYSTEM, INC. for revision of depreciation rates

Core Terms

deficit, depreciate, salvage, cable, embed, amortize, switcher, plant, retirement

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS, SUSAN W. LEISNER

Opinion

NOTICE OF PROPOSED AGENCY ACTION REGARDING THE APPROVAL OF NEW DEPRECIATION RATES

BY THE COMMISSION:

Indiantown Telephone System, Inc. (Indiantown or Company) has filed for changes in its depreciation rates to be effective as of January 1, 1983. Indiantown last applied for a comprehensive review of life and salvage factors in 1980 at which time whole life rates were prescribed. The current request for an overall review of life and salvage factors was filed pursuant to Florida Administrative Code Rule 25-4.175(7) which requires an overall review every three years. Additionally the Company has asked that the new rates be determined using the Remaining Life Method instead of the Average Service Life or Whole Life Method used in the past.

After reviewing the record, we make the following findings:

(1) New depreciation rates should be prescribed for Indiantown as of January 1, 1983.

(2) As we have done with other telephone companies, we approve the use of the Remaining Life Method.

(3) Indiantown **[*2]** has a net reserve dificit of $126,470, composed of a historic deficit of $21,985 and a prospective deficit of $104,475. The net reserve deficit calculation excludes those investments associated with the electromechanical central office switcher scheduled for retirement in 1984 and the embedded CPE accounts (Accounts 231.1 and 234.1). The historic deficit is the difference between the book reserve and the reserve that should have accumulated under the rates being prescribed. This historic deficit is brought about by such things as technological change, growth, and incorrect estimates of life and salvage. The prospective deficit is due to the difference between the life and salvage factors we now find appropriate and the previous life and salvage factors.

ATTACHMENT B

This prospective deficit is generally due to the replacement of older technologies and is based on retirements that are expected to occur in the future.

(4) The Company's projected retirement date for its electromechanical central office is reasonable.

(5) The replacement of the step-by-step equipment by a digital switcher is prudent.

(6) The Company's plans to continue using the analog circuit equipment with the **[*3]** proposed digital switching equipment is prudent.

(7) The depreciation rates and recovery schedules shown on Attachment I to this Order are just and reasonable and should be approved.

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current reserve levels and what the reserve levels should be using the new depreciation rates. As discussed previously, we have calculated the net reserve deficit to be $126,460 on a composite basis. While it is possible to make that correction through the new depreciation rates allowed for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the Company to separately recover the reserve deficit, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite **[*4]** remaining life of the embedded plant, which is estimated to be 15 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 15-year period is $104,475, and the amount to be amortized over a 5-year period is $21,985. This results in annual expenses of $6,965 and $4,397 respectively.

The company is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the should be included in these accounts without Commission approval. Likewise, each depreciable account's reserve should be restated to the level shown below and brought forward from that point. The book reserve total is not changed by the restatement of account reserves and the netting of the reserve deficits.

The restated reserve levels by account are shown below. These reserve levels should be shown on Company books or side records as of January 1, 1983, and brought forward from that time by account activity. These reserves **[*5]** should be shown in the Company's next depreciation study, updated to the implementation date of the new rates proposed in that study.

	Account	1-1-83 Restated Reserve By Account To Be Brought Forward By Annual Activity
212	Buildings	$46,683
221.1	Step	* 398,112
221.2	Circuit	142,178
221.4	Digital	

* Book Reserve

	Account	1-1-83 Restated Reserve By Account To Be Brought Forward By Annual Activity
231.1	Embedded CPE	* 10,612
231.2	Official Terminal Equipment	2,842
231.3	Pay Stations	12,376
231.5	Deaf	1,732
232	Station Connections - Drop	* 39,258
234	Embedded PBX	* 55,643
241	Pole Lines	10,685
242.1	Aerial Cable	6,070
242.2	Underground Cable	3,474
242.3	Buried Cable	285,771
242.4	Submarine Cable	252
244.0	Underground Conduit	4,341
261	Furniture and Office Equipment	12,706
264.1	Vehicles	24,548
264.2	Tractors	
264.3	Other Work Equipment	5,247

We have not included in the reserve deficit calculation the reserve relating to the investment in the electromechanical switcher retiring in 1984. The unrecovered investment in that switcher, as of January 1, 1983, is $56,154. For this amount we are ordering a capital recovery schedule for a three-year period beginning January **[*6]** 1, 1983. Annual expense to be booked for this recovery is $18,718. The 1983 additions being made to this switcher amount to $73,400. These additions will be retained for use with the replacing digital machine, and therefore should be booked directly to the digital account as incurred.

We are also requiring quarterly reports beginning January 1, 1984 showing plant balances and activity, reserve balances and activity, as well as any changes in plans, or in anticipated net salvage for this step switcher.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that each and every finding set out in the body of this Order and the depreciation rates and recovery schedules shown on Attachment I are approved and may be implemented as of January 1, 1983. It is further

ORDERED that the Company create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the historic and prospective deficit as set out in the body of this Order. It is further

ORDERED that the Company file quarterly reports beginning January 1, 1984 showing plant balances and activity, reserve balances and activity, as well as any changes in plans **[*7]** or in anticipated net salvage for the electromechanical switcher to be retired in 1984. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final agency action unless a person a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29(4), that must be received by the Commission Clerk by the close of business on January 31, 1984, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this Order shall become effective and final, as provided by Florida Administrative Code Rule 25-22.29(6), and as reflected in a subsequent order.

BY ORDER of the Florida Public Service Commission, this 12th day of JANUARY, 1984.

ATTACHMENT I

INDIANTOWN TELEPHONE SYSTEM

AUTHORIZED DEPRECIATION RATES AND COMPONENTS

Acct.#	**Description**	**Average Remaining Life (years)**	**Future Net Salvage (%)**	**Appropriate Reserve (%)**	**Remaining Life Rate (%)**
212	Buildings	34		8.2	2.7
221.1	Step Switching	Three year recovery schedule			
221.2	Circuit	7.6		38.44	8.1
221.4	Digital	15.4			6.5
231.1	Embedded CPE	5	20	5.18	15.0
231.2	Official CPE	6.5		35.0	10.0
231.3	Pay Stations	5.1		49.0	10.0
231.5	Deaf	4.3		57.0	10.0
232.1	Station Connections - Drop				5.0
234	Embedded PBX	2.6	10	50.4	15.3
241	Pole Line	18	-30	36.4	5.2
242.1	Aerial Cable	15.5	-20	27.0	6.0

INDIANTOWN TELEPHONE SYSTEM

AUTHORIZED DEPRECIATION RATES AND COMPONENTS

Acct.#	Description	Average Remaining Life (years)	Future Net Salvage (%)	Appropriate Reserve (%)	Remaining Life Rate (%)
242.2	Underground Cable	32		7.2	2.9
242.3	Buried Cable	17.1	- 5	22.92	4.8
242.4	Submarine Cable	16		36.0	4.0
244.0	Underground Conduit	40		20.0	2.0
261	Furniture & Office Equipment	11.2	3	19.72	6.9
264.1	Vehicles	3.8	15	38.26	12.3
264.2	Tractors	10	14		8.6
264.3	Other Work Equipment	11.3		24.29	6.7

[*8]

FL Public Service Commission Decisions

1984 Fla. PUC LEXIS 422

Florida Public Service Commission

July 9, 1984

DOCKET NO. 830577-TP; ORDER NO. 13495, 84 FPSC 39

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 422 *

In re: Application of GULF TELEPHONE COMPANY for a change in depreciation rates

Core Terms

depreciate, surplus, amortize, cable, salvage, carrier, station, embed, plant, tower, furniture, estimate, restate, switch, gulf, has

Panel: ; The following Commissioners participated in the disposition of the matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS

Opinion

NOTICE OF PROPOSED AGENCY ACTION REGARDING THE APPROVAL OF NEW DEPRECIATION RATES

BY THE COMMISSION:

Gulf Telephone Company (Gulf or Company) has filed for changes in its depreciation rates to be effective as of January 1, 1984. Gulf last applied for a comprehensive review of life and salvage factors in 1980 at which time whole life rates were prescribed. The current request for an overall review of life and salvage factors was filed pursuant to Florida Administrative Code Rule 25-4.175(7) which requires an overall review every three years. The Company has asked that the new rates be determined using the Remaining Life Method instead of the Average Service Life or Whole Life Method used in the past. The Company has also requested a waiver for accounting and depreciation purposes from the subcategorization requirements of Florida Administrative Code Rule 25-4.17 for the following accounts: Buildings, Subscriber Carrier, Buried Cable, and Furniture or Officer Equipment.

After reviewing the record, we make the **[*2]** following findings:

(1) New depreciation rates should be prescribed for Gulf as of January 1, 1984.

(2) As we have done with other telephone companies, we approve the use of the Remaining Life Method.

(3) Gulf has a net reserve surplus of $115,874, composed of a historic surplus of $43,553 and a prospective surplus of $72,321. The historic surplus is the difference between the book reserve and the reserve that should have accumulated under the rates in effect at the time of the current depreciation study. This historic surplus is brought about by such things as technological change, growth, and incorrect estimates of life and salvage. The prospective surplus is due to the difference between the life and salvage factors we now find appropriate and the

previous life and salvage factors. This prospective surplus is generally due to the replacement of older technologies and is based on retirements that are expected to occur in the future.

(4) We find that the Company's projected retirement dates for its electromechanical central offices are reasonable.

(5) The Company does not expect to make any additions to its electromechnical central offices prior to their retirement; **[*3]** therefore, there is no need to provide for the recovery of additions.

(6) The depreciation rates and recovery schedules shown on Attachment I to this Order are just and reasonable and should be approved.

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current reserve levels and what the reserve levels should be using the new depreciation rates. As discussed previously, we have calculated the net reserve surplus to be $115,874 on a composite basis. While it is possible to make that correction through the new depreciation rates allowed for embedded plant, we have chosen to amortize the composite reserve surplus of all depreciable plant over a specific period. By allowing the Company to separately amortize the reserve surplus, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

We are ordering two amortization schedules for the reserve surplus. That portion of the surplus that is attributable to changes in prospective life and salvage values is to be amortized over the **[*4]** composite remaining life of the embedded plant, which is estimated to be 14 years. That portion of the surplus that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be amortized over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized for a 14-year period is $72,321, and the amount to be amortized over a 5-year period is $43,553. This results in a decrease in annual expenses of $5,116 and $8,711, respectively.

The Company is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the two surplus amounts. No further surpluses or deficits should be included in these accounts without Commission approval. Likewise, each depreciable account's book reserve should be restated to the level indicated below and brought forward from that point. The book reserve total is not changed by the restatement of account reserves and the netting of the reserve imbalance.

The Company estimates that an investment of $2,030,772 in crossbar switching equipment will be retried at Perry about **[*5]** the end of 1984 and replaced by a digital switch. The Company's estimated net salvage of -5% gives an additional $101,538 to be recovered under the recovery schedule. The reserve for this retiring investment as of January 1, 1984 was $1,168,912, so the annual accrual under a 3-year recovery schedule would be $321,133.

The restated reserve levels by account are shown below. These reserve levels should be shown on Company books and side records as of January 1, 1984, and brought forward from that time by account activity. This reserve should be shown in the Company's next depreciation study, updated to the implementation date of the new rates proposed in that study.

	Account	**1-1-84 Restated Reserve to be Brought Forward by Annual Activity**
212	Buildings	145,178
221.0	COE-Digital Switching	213,192

	Account	1-1-84 Restated Reserve to be Brought Forward by Annual Activity
221.1	COE-Crossbar Switching	115,451
221.2	COE-Radio	10,464

	Account	1-1-84 Restated Reserve to be Brought Forward by Annual Activity
221.3	COE-Microwave	309,422
221.6	COE-Subscriber Carrier	
221.6(a)	COE-Analog Carrier	23,884
221.6(b)	COE-Digital Carrier	8,038
231.1	Station Apparatus-Embedded CPE	
231.2	Offical Telephone	32,301
231.3	Pay Stations	28,659
232.1	Station Connections - Inside	
234.1	Embedded PBX	
234.2	Official PBX	21,553
241.1	Pole Lines	27,453
241.2	Tower and Tower Foundation	35,936
241.2(a)	Tower	
241.2(b)	Tower Foundation	
242.1	Aerial Cable	20,078
242.2	Underground Cable	45,655
242.3	Buried Cable - Total	1,104,781
242.3(a)	B. Cable - nonfilled	659,984
242.3(b)	B. Cable - filled	444,797
242.3(c)	Drop and Block	192,880
244.1	Underground Conduit	20,605
261.1	Furniture and Office Equipment	47,217
261.1(a)	Furniture	24,195

	Account	1-1-84 Restated Reserve to be Brought Forward by Annual Activity
261.1(b)	Office Equipment	23,022
261.2	Computers	24,233
261.3	Supply Equipment	1,568
261.4	Display Equipment	1,123
264.1	Passenger Cars	17,040
264.2	Service Vehicles	35,431
264.3	Heavy Trucks	24,190
264.4	Heavy Work Machines	18,925
264.5	Test Equipment and Tools	21,949
264.5	Shop Equipment	5,032

[*6]

For the reasons stated below, we have decided to grant the Company's request for a waiver from the subcategorization requirements of Florida Administrative Code Rule 25-4.17 for the Building account only. For the other accounts the request for a waiver will be denied. The waiver for the Building account is proper because the Company has provided an unusually thorough depreciation study for this account and because of the small number of major buildings owned by the Company. The other accounts for which a waiver was requested contain different types of equipment with significantly different life and salvage factors. Also the mix of plant investment in each account is changing rapidly. Failure to separate these accounts into subaccounts for depreciation purposes will result in the composite rate set at one time becoming increasingly inaccurate and inappropriate over time. Therefore, these accounts should be split into subaccounts and the Company's request for a waiver is denied.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that each and every finding set out in the body of this Order and the depreciation rates and recovery schedules **[*7]** shown on Attachment I are approved and may be implemented as of January 1, 1984. It is further

ORDERED that the Company create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the historic and prospective deficit as set out in the body of this Order. It is further

ORDERED that the Company's request for a waiver of the subcategorization requirements, of Florida Administrative Code Rule 25-4.17 is granted for the Building account and denied for the Subscriber Carrier, Buried Cable, and Furniture or Office Equipment accounts. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final agency action unless a person adversely affected by the action taken herein files a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29(4), that must be received by the Commission Clerk by the close of business on July 30, 1984, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this Order shall become effective and final, as provided by Florida Administrative Code **[*8]** Rule 25-22.29(6), and as reflected in a subsequent order.

ATTACHMENT B

By ORDER of the Florida Public Service Commission, this 9th day of JULY, 1984.

ATTACHMENT I

	Account Description	Average Remaining Life (years)	Future Net Salvage (%)	Appropriate Reserve (%)	Remaining Life Rate (%)
212	Buildings	25.4	6	20.6	2.9
221.0	COE-Digital Switching	15.3	0	65.8	6.5
221.1	COE-Crossbar	4.4	(5)	65.8	8.9
221.2	COE-Radio Telephone	5.8	(6)	55.2	8.8
221.3	COE-Microwave	5.9	(2)	57.4	7.6
221.6(a)	COE-Analog Carrier	3.1	20	38.7	13.3
221.6(b)	COE-Digital Carrier	10.6	5	3.5	8.6
231.1	Station APP. - Embedded	4.2	10	31.6	13.9
231.2	Offical Telephone	4.0	0	63.6	9.1
231.3	Pay Stations	5.2	0	48.0	10.0
232.1	Station Connections - Inside			(10-year amortization schedule)	
234.1	Large PBX - Embedded	3.1	5	45.2	16.1
234.2	Large PBX Official	5.1	5	34.4	11.9
241.1	Pole Lines	11.7	(20)	56.2	5.5
241.2	Tower and Tower Foundation	19.1	0	37.1	3.4
242.1	Aerial Cable	9.9	(5)	40.0	6.6
242.2	Underground Cable	29.3	(5)	8.9	3.3
242.3(a)	B. Cable - Nonfilled	7.8	(3)	49.4	6.9
242.3(b)	B. Cable - Filled	26.2	(3)	13.1	3.4
242.3(c)	Drop and Block	19.4	(3)	25.6	4.0
244	Underground Conduit	46.7	(4)	6.9	2.1
261.1(a)	Furniture	13.0	10	31.5	4.5
261.1(b)	Office Equipment	5.0	0	58.3	8.3
261.2	Computer	5.2	0	13.3	16.7
261.3	Supply Equipment	16.2	10.0	17.1	4.5
261.4	Display Equipment	10.5	0.0	12.5	8.3

		Average Remaining Life (years)	Future Net Salvage (%)	Appropriate Reserve (%)	Remaining Life Rate (%)
264.1	Passenger Cars	2.0	20	53.3	13.3
264.2	Service Vehicles	2.9	17	48.6	11.9
264.3	Heavy Trucks	4.9	18	45.5	7.5
264.4	Heavy Work Machines	4.9	18	45.5	7.5
264.5	Test Equipment and Tools	7.5	0	37.5	8.3
264.6	Shop Equipment	10.0	0	33.3	6.7

[*9]

1984 Fla. PUC LEXIS 389

Florida Public Service Commission

July 19, 1984

DOCKET NO. 830582-GU; ORDER NO. 13528, 84 FPSC 106

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 389 *

In re: Application of Miller Gas Company for new depreciation rates

Core Terms

depreciate, deficit, plant, amortize, salvage, agency's action, calculate, composite, estimate, restate, embed, furniture, transport, customer, annual, denote, meter

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, SUSAN W. LEISNER, KATIE NICHOLS

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER GRANTING NEW DEPRECIATION RATES

BY THE COMMISSION:

This matter was initiated upon request of Miller Gas Company (Miller or Company) for new depreciation rates. Miller last applied for depreciation rates in 1974. At that time, whole life rates were prescribed for all accounts. The current study is an overall review of life and salvage factors in compliance with Florida Administrative Code Rule 25-7.45(7), in which the Company has proposed continuation of their existing whole life rates. It is our opinion that even if current life and salvage parameters are still viable estimates a move to a reserve sensitive method of depreciation rate design should be made.

We have reviewed the requested changes and the supporting data and find that the depreciation rates effective July 1, 1984, as shown on Appendix A to this order and incorporated herein are approved.

Appropriate Depreciation Reserve Level and Correction of the Reserve Deficit

Because we have **[*2]** determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current booked reserve levels and what the reserve levels would have been if the new depreciation rates had been in effect. We have calculated the net reserve deficit to be $19,024 on a composite basis. While it is possible to make that correction through the new depreciation rates allowed for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the Company to separately recover the reserve deficit, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

ATTACHMENT B

We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant, which is estimated to be 20 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological **[*3]** change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 20-year period is $15,881, and the amount to be amortized over a 5-year period is $3,143. This results in annual expenses of $794 and $629, respectively.

The Company is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the two deficit amounts. No further deficits should be included in these accounts without Commission approval. Likewise, each depreciable account's reserve should be restated to the level shown in Appendix B to this Order, which is incorporated herein, and brought forward from that point. The book reserve total is not changed by the setting of the reserve imbalance and restatement of the account reserves. These reserve levels should be shown on Company books or side records as of January 1, 1984, and brought forward from that time by account activity. These reserves should be shown in the Company's next depreciation study, updated to the implementation date of the new rates proposed in that study.

This **[*4]** docket will be closed unless an appropriate petition for hearing is filed by one whose substantial interest may or will be effected by this proposed agency action as provided by Florida Administrative Code Rule 25-22.29. It is, therefore

ORDERED by the Florida Public Service Commission, that depreciation rates and amortization schedules as set forth in this order be and the same is hereby approved for Miller Gas Company effective July 1, 1984. It is further

ORDERED that the provisions of this order, issued as proposed agency action, shall become final agency action unless a person adversely effected by the action taken herein files a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29(4), that must be received by the Commission Clerk by the close of business on August 8, 1984, in the form provided by Florida Administrative Code Rule 25-22.367(a) and (f). It is further

ORDERED that in the absence of such a petition this order shall become effective and final, as provided by Florida Administrative Code Rule 25-22.29(6), and reflected in a subsequent order.

By ORDER of the Florida Public Service Commission this 19th day of July, 1984.

[*5] APPENDIX A

COMPARISON OF DEPRECIATION RATES AND COMPONENTS

	APPROVED			
	Average Remaining Life	**Future Net Salvage**	**Appropriate Reserve** *	**Remaining Life Rate**
Account	(years)	(%)	(%)	(%)

* Denotes Calculated Theoretical Reserve

Implied Average Service Life

COMPARISON OF DEPRECIATION RATES AND COMPONENTS

		APPROVED			
		Average Remaining Life	**Future Net Salvage**	**Appropriate Reserve** *	**Remaining Life Rate**
Distribution Plant					
376	Mains	28	(5)	40.6	2.3
380	Services	26	(20)	42.0	3.0
381	Customer Meters	6.9	0	72.4	4.0
383	House Regulators	13.3	0	56.11	3.3
General Plant					
391	Office Furniture and Equipment	6.7	2	47.75	7.5
392	Transportation Equipment	3.4	15	43.86	12.1
394	Tools and Locator Equipment	8.3	0	44.39	6.7
397	Communication Equipment	# 15.3	0		7.0
398	Miscellaneous Equipment	5.5	0	78.0	4.0

APPENDIX B

ANALYSIS OF RESERVE POSITION

Account		**Restated Reserve By Account To Be Brought Forward By Annual Activity** *
Distribution Plant		
376	Mains	$524,459

* Denotes calculated reserve

ANALYSIS OF RESERVE POSITION

	Account	Restated Reserve By Account To Be Brought Forward By Annual Activity *
380	Services	196,076
381	Customer Meters	126,658
383	House Regulators	30,155
General Plant		
391	Office Furniture and Equipment	6,125
392	Transportation Equipment	29,102
394	Tools and Locator Equipment	1,324
397	Communication Equipment	13,318
398	Miscellaneous Equipment	537
	Total	$927,754

[*6]

[1984 Fla. PUC LEXIS 376](#)

Florida Public Service Commission

July 24, 1984

DOCKET NO. 840045-GU; ORDER NO. 13538, 84 FPSC 220

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 376 *

In re: Depreciation Study of CITY GAS COMPANY OF FLORIDA

Core Terms

plant, depreciate, furniture, deficit, station, truck, meter, transport, garage, shop, amortize, accrual, staff, salvage, embed, composite

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS, SUSAN W. LEISNER

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING NEW DEPRECIATION RATES

BY THE COMMISSION:

On February 6, 1984, City Gas Company of Florida (City Gas) filed a depreciation study seeking Florida Public Service Commission approval of new depreciation rates pursuant to Florida Administrative Code Rule 25-7.45. Since our approval of City Gas's present depreciation rates in 1976, net plant balances, composite ages and lives, as well as current life and salvage have changed as a result of normal and technological changes. Taking those changes into consideration, we have determined that a re-evaluation and implementation of new depreciation rates is warranted.

We have reviewed the requested changes and the supportive data submitted with reference to the enumerated accounts and find that the depreciation rates and capital recovery schedules, effective January 1, 1983, as shown on Appendices A and C to this Order and incorporated herein, are approved.

Appropriate Depreciation Reserve Level **[*2]** and Correction of the Reserve Deficit

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the current booked reserve levels and what the reserve levels would have been if the new depreciation rates had been in effect. We have calculated the net reserve possible to make that correction through the new depreciation rates allowed for embedded plant, we have chosen to amortize the composite reserve deficit of all depreciable plant over a specific period. By allowing the company to separately recover the

ATTACHMENT B

reserve deficit, we are bringing the booked reserves for the accounts up to the theoretical reserve. Therefore, the rates for the embedded plant are the same as the rates for new plant.

1

We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective **[*3]** life and salvage values is to be amortized over the composite remaining life of the embedded plant, which is estimated to be 24 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit. The amount to be amortized over a 24-year period is $675,987 and the amount to be amortized over a 5-year period is $239,669. This results in annual expenses of $28,166 and $47,934, respectively.

City Gas is to create two separate subaccounts in the Accumulated Depreciation Reserve account to reflect the amortization of the two deficit amounts. No further deficits should be included in these accounts without our approval. Likewise, each depreciable account's reserve should be restated to the level shown in Appendix B to this Order, which is incorporated herein, and brought forward from that point. The book reserve total is not changed by the setting of the reserve imbalance and restatement of the account reserves. These reserve levels should be shown on **[*4]** City Gas's books or side records as of January 1, 1984, and brought forward from that time by account activity. These reserves should be shown in City Gas's next depreciation study, updated to the implementation date of the new rates proposed in that study.

This docket will be closed unless an appropriate petition for hearing is filed by one whose substantial interest may or will be effected by this proposed agency action as provided by Florida Administrative Code Rule 25-22.29. It is, therefore,

ORDERED by the Florida Public Service Commission that the depreciation rates and amortization schedules as set forth in this Order be and the same are hereby approved for City Gas Company of Florida effective January 1, 1984. It is further

ORDERED that the action proposed herein is preliminary in nature and will not become effective or final, except as provided by Florida Administrative Code Rule 25-22.29. It is further

ORDERED that any person adversely affected by the action proposed herein may file a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29. Said petition must be received by the Commission Clerk on or before August 14, 1984, in **[*5]** the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this order shall become effective on August 15, 1984 as provided by Florida Administrative Code Rule 25-22.29(6).

By ORDER of the Florida Public Service Commission, this 24th day of JULY, 1984.

ATTACHMENT I

CITY GAS COMPANY

Comparison of Depreciation Rates and Components

CURRENT

[1] This deficit does not include investment associated with the meters, house regulators and computer accounts because of prudency questions being investigated as part of the rate case that could affect the depreciation reserve and theoretical reserve.

	Account Description	Average Service Life (years)	Average Net Salvage (%)	Whole Life Rate (%)
	Distribution Plant			
375	Structures & Improvements	40	25	1.9
376	Mains	40	(20)	3.0
379	Meas. & Reg. Station Equipment	30	(5)	3.5
380	Services	35	(25)	3.6
381	Meters	30	0	3.3
383	House Regulators	30	0	3.3
385	Ind. Meas. & Reg. Station Equip.	15	0	6.7
387	Other Equipment	20	0	5.0
	General Plant			
390	Structures & Improvements	40	20	2.0
391	Ofc. Furniture & Equipment	15	5	6.3
391.1	Furniture			
391.2	Office Equipment			
391.3	Computer - Embedded	15	5	6.3
391.3	Computer - New Additions			
392	Transportation	8	10	11.3
392.1	Cars			
392.2	Light Trucks			
392.3	Heavy Trucks			
393	Stores Equipment	25	0	4.0
394	Tools, Shop & Garage Equipment	15	0	6.7
395	Laboratory Equipment	20	0	5.0
397	Communications Equipment	10	10	9.0
398	Miscellaneous Equipment	15	0	6.7

[*6]

CITY GAS COMPANY

Comparison of Depreciation Rates and Components

COMPANY PROPOSED

	Account Description	Average Remaining Life (years)	Future Net Salvage (%)	Estimated Reserve (%)	Remaining Life Rate (%)
	Distribution Plant				
375	Structures & Improvements	38.55	10	4.42	2.22
376	Mains	29.57	(10)	28.31	2.76
379	Meas. & Reg. Station Equipment	17.07	(5)	44.23	3.56
380	Services	21.15	(40)	27.08	5.34
381	Meters	19.96	(5)	20.25	4.25
383	House Regulators	18.63	(10)	20.57	4.80
385	Ind. Meas. & Reg. Station Equip.	8.62	0	46.07	6.26
387	Other Equipment	13.40	0	34.72	4.87
	General Plant				
390	Structures & Improvements	25.39	0	45.48	2.15
391	Ofc. Furniture & Equipment	10.35	5	98.40	(.33)
391.1	Furniture				
391.2	Office Equipment				
391.3	Computer - Embedded	2.00	5	10.30	42.35
391.3	Computer - New Additions	6.0	5.0	0.0	15.8
392	Transportation	5.88	15	50.39	5.89
392.1	Cars				
392.2	Light Trucks				
392.3	Heavy Trucks				
393	Stores Equipment	15.11	0	85.27	.97
394	Tools, Shop & Garage Equipment	13.91	6	13.20	5.81
395	Laboratory Equipment	16.43	0	25.66	4.52
397	Communications Equipment	4.27	0	87.29	2.98
398	Miscellaneous Equipment	10.78	0	44.75	5.13

[*7]

CITY GAS COMPANY

Comparison of Depreciation Rates and Components

STAFF RECOMMENDED

Average	Future	Remaining

	Account Description	Remaining Life (years)	Net Salvage (%)	Appropriate Reserve * (%)	Life Rate (%)
	Distribution Plant				
375	Structures & Improvements	38.0	10.0	4.5	2.3
376	Mains	27.0	(10.0)	29.7	3.0
379	Meas. & Reg. Station Equipment	16.9	(5.0)	45.9	3.5
380	Services	25.0	(30.0)	34.4	3.8
381	Meters	20.0	0	# 20.3	4.0
383	House Regulators	18.7	0	# 20.6	4.2
385	Ind. Meas. & Reg. Station Equip.	12.3	0	38.5	5.0
387	Other Equipment	13.2	0	34.0	5.0
	General Plant				
390	Structures & Improvements	25.0	0	37.5	2.5
391	Ofc. Furniture & Equipment				
391.1	Furniture	9.3	5	50.8	4.8
391.2	Office Equipment	9.2	5	32.6	6.8
391.3	Computer - Embedded		Recovery Schedule		
391.3	Computer - New Additions	6.0	5.0	0.0	15.8
392	Transportation				
392.1	Cars	4.2	16	33.6	12.0
392.2	Light Trucks	5.1	15	30.8	10.6
392.3	Heavy Trucks	4.7	10	47.7	9.0
393	Stores Equipment	14.7	0	41.2	4.0
394	Tools, Shop & Garage Equipment	13.3	6	10.7	6.3
395	Laboratory Equipment	15.3	0	23.5	5.0
397	Communications Equipment	4.3	5	61.0	7.9
398	Miscellaneous Equipment	10.1	0	32.7	6.7

[*8]

ATTACHMENT III

CITY GAS COMPANY

ANALYSIS OF RESERVE POSITION

1984 STUDY

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* Denotes Staff calculated theoretical reserve.

Actual Book Reserve %

	Account Description	Investment $	Depreciation Reserve 1-1-84 $	Reserve %
	Distribution Plant			
375	Structures & Improvements	768,824	33,988	4.42
376	Mains	32,776,568	9,278,313	28.31
379	Meas & Reg. Station Equip.	342,260	151,380	44.23
380	Services	12,326,385	3,337,719	27.08
381	Meters **			
383	House Regulators **			
385	Ind. Meas. & Reg. Station Equip.	276,013	127,147	46.07
387	Other Equipment	121,372	42,146	34.72
	General Plant			
390	Structures & Improvements	505,233	229,795	45.49
391	Total Ofc. Furniture & Equipment	345,444	339,906	98.40
391.1	Furniture	* 158,010		
391.2	Office Equipment	* 187,434		
391.3	Computer **			
392	Total Transportation Equipment	635,975	319,496	50.24
392.1	Cars	* 118,023		
392.2	Light Trucks	* 506,236		
392.3	Heavy Trucks	* 11,716		
393	Stores Equipment	16,358	13,949	85.28
394	Tools, Shop & Garage Equipment	417,224	55,086	13.21
395	Laboratory Equipment	24,840	6,373	25.66
397	Communications Equipment	193,761	169,125	87.29
398	Miscellaneous Equipment	12,250	5,482	44.76
	Total	$48,762,507	$14,109,905	
	Annual Accrual			

[*9]

CITY GAS COMPANY

** Excluded from calculations

* Staff proposes new subaccounts for what has been a composite account

Melinda Marzicola

ATTACHMENT B

ANALYSIS OF RESERVE POSITION

1984 STUDY

	Account Description	Historic Theoretical Reserve %	Historic Theoretical Reserve $	Historic Deficit $
	Distribution Plant			
375	Structures & Improvements	4.7	36,135	2,147
376	Mains	29.7	9,734,641	456,328
379	Meas & Reg. Station Equip.	49.4	169,076	17,696
380	Services	28.6	3,525,346	187,627
381	Meters **			
383	House Regulators **			
385	Ind. Meas. & Reg. Station Equip.	47.3	130,554	3,407
387	Other Equipment	33.0	40,053	(2,093)
	General Plant			
390	Structures & Improvements	30.0	151,570	(78,225)
391	Total Ofc. Furniture & Equipment	43.7	150,959	(188,947)
391.1	Furniture			
391.2	Office Equipment			
391.3	Computer **			
392	Total Transportation Equipment	34.9	221,955	(97,541)
392.1	Cars			
392.2	Light Trucks			
392.3	Heavy Trucks			
393	Stores Equipment	41.2	6,739	(7,210)
394	Tools, Shop & Garage Equipment	11.3	47,146	(7,940)
395	Laboratory Equipment	23.5	5,837	(536)
397	Communications Equipment	64.8	125,557	(43,568)
398	Miscellaneous Equipment	32.7	4,006	(1,476)
	Total		$14,349,574	$239,669
	Annual Accrual			$47,934

CITY GAS COMPANY

ANALYSIS OF RESERVE POSITION

1984 STUDY

	Account Description	Staff Theoretical Reserve %	Staff Appropriate Reserve $	Prospective Deficit $
	Distribution Plant			
375	Structures & Improvements	4.5	34,597	[Illegible Word]
376	Mains	29.7	9,734,641	[Illegible Word]
379	Meas & Reg. Station Equip.	45.9	157,097	(11,979)
380	Services	34.4	4,240,276	714,930
381	Meters **			
383	House Regulators **			
385	Ind. Meas. & Reg. Station Equip.	38.5	106,265	(24,289)
387	Other Equipment	34.0	41,266	1,213
	General Plant			
390	Structures & Improvements	37.5	189,462	37,892
391	Total Ofc. Furniture & Equipment		*	(9,587)
391.1	Furniture	50.8	80,269	
391.2	Office Equipment	32.6	61,103	
391.3	Computer **			
392	Total Transportation Equipment		*	(20,789)
392.1	Cars	33.6	39,656	
392.2	Light Trucks	30.8	155,921	
392.3	Heavy Trucks	47.7	5,589	
393	Stores Equipment	41.2	6,739	0
394	Tools, Shop & Garage Equipment	10.7	44,643	[Illegible Word]
395	Laboratory Equipment	23.5	5,837	0
397	Communications Equipment	61.0	118,194	(7,363)
398	Miscellaneous Equipment	32.7	4,006	0
	Total		$15,025,561	$675,987
	Annual Accrual			$28,166

[*10]

ATTACHMENT II

CITY GAS COMPANY

Comparison of Depreciation Expenses

		CURRENT		
		Whole Life		
	Account Description	**Investment**	**Rate**	**Accruals**
		$	(%)	$
	Distribution Plant			
375	Structures & Improvements	768,824	1.90	14,608
376	Mains	32,776,568	3.00	983,297
379	Meas. & Reg. Station Equipment	342,260	3.50	11,979
380	Services	12,326,385	3.60	443,750
381	Meters	# 4,340,319	3.30	143,231
383	House Regulators	# 1,491,967	3.30	49,235
385	Ind. Meas. & Reg. Station Equip.	276,013	6.70	18,493
387	Other Equipment	121,372	5.00	6,069
	General Plant			
390	Structures & Improvements	505,233	2.00	10,105
391	Total Ofc. Furniture & Equipment	345,444	6.30	21,763
391.1	Furniture	* 158,010		
391.2	Office Equipment	* 187,434		
391.3	Computer	# 319,810	6.30	20,148
392	Total Transportation Equipment	635,975	11.30	71,865
392.1	Cars	* 118,023		
392.2	Light Trucks	* 508,236		
392.3	Heavy Trucks	* 11,716		
393	Stores Equipment	16,358	4.00	654
394	Tools, Shop & Garage Equipment	417,224	6.70	27,954
395	Laboratory Equipment	24,840	5.00	1,242
397	Communications Equipment	193,761	9.00	17,438
398	Miscellaneous Equipment	12,250	6.70	821
	Total	$54,914,603		$1,842,652

* Staff proposal is for homogeneous subaccounts where company's proposal was for a Composite of different types of equipment.

Questions of prudency being investigated in the rate case could necessitate reconsideration of these accounts as part of the rate case.

Melinda Marzicola

ATTACHMENT B

CITY GAS COMPANY

Comparison of Depreciation Expenses

		CURRENT Whole Life	
Account Description	**Investment**	**Rate**	**Accruals**
Historic Reserve Deficit			
Prospective Reserve Deficit			

[*11]

CITY GAS COMPANY

Comparison of Depreciation Expenses

		COMPANY PROPOSED Remaining Life		
				Change In
	Account Description	**Rate**	**Accruals**	**Accruals**
		%	$	$
	Distribution Plant			
375	Structures & Improvements	2.22	17,068	2,460
376	Mains	2.76	904,633	(78,664)
379	Mess. & Reg. Station Equipment	3.56	12,184	205
380	Services	5.34	658,229	214,479
381	Meters	4.25	184,464	41,233
383	House Regulators	4.80	71,614	22,379
385	Ind. Meas. & Reg. Station Equip.	6.26	17,278	(1,215)
387	Other Equipment	4.87	5,911	(158)
	General Plant			
390	Structures & Improvements	2.15	10,863	758
391	Total Ofc. Furniture & Equipment	(.33)	(1,140)	(22,903)
391.1	Furniture			
391.2	Office Equipment			
391.3	Computer	42.35	135,440	115,292

CITY GAS COMPANY

Comparison of Depreciation Expenses

		COMPANY PROPOSED		
		Remaining Life		
				Change In
	Account Description	**Rate**	**Accruals**	**Accruals**
392	Total Transportation Equipment	5.89	37,459	(34,406)
392.1	Cars			
392.2	Light Trucks			
392.3	Heavy Trucks			
393	Stores Equipment	.97	159	(495)
394	Tools, Shop & Garage Equipment	5.81	24,241	(3,713)
395	Laboratory Equipment	4.52	1,123	(119)
397	Communications Equipment	2.98	5,774	(11,664)
398	Miscellaneous Equipment	5.13	628	(193)
	Total		$2,085,928	$243,276
	Historic Reserve Deficit			
	Prospective Reserve Deficit			

[*12]

CITY GAS COMPANY

Comparison of Depreciation Expenses

		STAFF RECOMMENDED		
		Remaining Life		
				Change In
	Account Description	**Rate**	**Accruals**	**Accruals**
		(%)	$	$
	Distribution Plant			
375	Structures & Improvements	2.3	17,683	3,075
376	Mains	3.0	983,297	0
379	Meas. & Reg. Station Equipment	3.5	11,979	0
380	Services	3.8	468,403	24,652

CITY GAS COMPANY

Comparison of Depreciation Expenses

			STAFF RECOMMENDED	
			Remaining Life	
				Change In
	Account Description	**Rate**	**Accruals**	**Accruals**
381	Meters	4.0	173,613	30,382
383	House Regulators	4.2	62,663	13,428
385	Ind. Meas. & Reg. Station Equip.	5.0	13,801	(4,692)
387	Other Equipment	5.0	6,069	0
	General Plant			
390	Structures & Improvements	2.5	12,631	2,526
391	Total Ofc. Furniture & Equipment		*	
391.1	Furniture	4.8	7,584	(2,371)
391.2	Office Equipment	6.8	12,746	938
391.3	Computer	Recovery Schedule	90,288	70,140
392	Total Transportation		*	
392.1	Cars	12.0	14,163	826
392.2	Light Trucks	10.6	53,661	(3,543)
392.3	Heavy Trucks	9.0	1,054	(270)
393	Stores Equipment	4.0	654	0
394	Tools, Shop & Garage Equipment	6.3	26,285	(1,669)
395	Laboratory Equipment	5.0	1,242	0
397	Communications Equipment	7.9	15,307	(2,131
398	Miscellaneous Equipment	6.7	821	0
	Total		$1,973,944	$131,292
	Historic Reserve Deficit		47,934	47,934
	Prospective Reserve Deficit		28,166	28,166
			$2,050,044	$207,392

[*13]

ATTACHMENT B

FL Public Service Commission Decisions

End of Document

1984 Fla. PUC LEXIS 35

Florida Public Service Commission

December 14, 1984

DOCKET NO. 840052-TL; ORDER NO. 13918, 84 FPSC 84

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 35 *

In re: Represcription of depreciation rates for ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY

Core Terms

deficit, cable, depreciate, amortize, station, notice, plant, bury, calculate, was, telephone, aerial, switch, staff, central office, replacement, submarine, carrier, annual, embed

Panel: ; The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, SUSAN W. LEISNER, JOHN R. MARKS, III, KATIE NICHOLS

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING REPRESCRIPTION OF DEPRECIATION RATES

BY THE COMMISSION:

Florida Administrative Code Rule 25-4.175 requires telephone companies to file a comprehensive depreciation study at least once every three years. Acting pursuant to that rule, St. Joseph Telephone and Telegraph Company (St. Joe or the Company) filed a depreciation study on February 9, 1984. The Company's last complete represcription was in 1980. However, a limited represcription of selected accounts was carried out in 1982.

St. Joe's current study was compiled in 1983, prior to the implementation of Florida Administrative Code Rule 25-4.17, requiring the subcategorization of accounts. The Company's study thus did not meet the Commission's current requirement that individual accounts be listed by subcategory. At the staff's request, however, the Company filed supplemental information which allowed the calculation of depreciation rates for additional subcategories.

Upon review of **[*2]** the Company's study, we find that certain changes in depreciation rates, recovery schedules and expenses are required. The approved depreciation rates and components are set out on Attachment 1, appended to this order. The implementation date of the new rates shall be January 1, 1984, as the Company has requested.

RESERVE DEFICIT

Staff has calculated the Company's bottom-line net reserve deficit to be $1,156,215. This total deficit is comprised basically of two components: the historic deficit and the prospective deficit. The historic deficit represents the difference between the book reserve and that reserve that should have been accumulated under rates currently prescribed by the Commission. The historic deficit is brought about by such things as technological change, change in mix of plant, and incorrect estimates of plant life and salvage values. The amount of the historic deficit in this case is $529,002. The second, prospective, component of the total deficit is due to changes in life and salvage factors found appropriate for the future. These changes are generally due to the replacement of older technologies and relate to the life of the plant now being used **[*3]** to provide service. The amount of the prospective deficit is $627,213.

Given the nature of the historic component of the total reserve deficit, we believe that it should be written off as quickly as possible. Although we have in recent represcription cases allowed the amortization of the historic deficit over a five-year period, we agree with the staff that in this case a one-year write-off period for the $529,002 is appropriate. Based on an analysis of the Company's projected 1984 earnings submitted in Docket No. 820531-TP, it appears that the Company will be able to absorb this additional expense and still earn at least its maximum 16% return on equity. We do not, therefore, believe that the shortened amortization period will produce a hardship on the Company or its ratepayers.

As for the prospective reserve deficit, since it relates to the remaining life of embedded investment, we find that an amortization period of eleven years would be appropriate. This will result in an increase in annual depreciation expense of $57,019.

Because we have determined that new depreciation rates are appropriate, we must also provide for the recovery of the difference between the **[*4]** current reserve levels and what the reserve levels should be using the new depreciation rates (Attachment 2). The theoretical reserves we have calculated are the reserves to be brought forward on the Company books as of January 1, 1984. The book reserve total is not changed by the restatement of account reserves and netting of the reserve imbalance. By allowing the Company to separately amortize the reserve deficit, we are bringing the booked reserves, by individual account, up to the theoretical reserve - with the exception of the accounts excluded per the footnote to Attachment 2. Therefore, the rates for the embedded plant are the same as the rates for new plant.

The Company is to create a separate subaccount in the Accumulated Depreciation Reserve to reflect the amortization of the prospective deficit. No further surpluses or deficits should be included in these accounts without Commission approval.

UNRECOVERED CENTRAL OFFICE INVESTMENT IN PORT ST. JOE AND BLOUNTSTOWN OFFICES

The Company is currently using a five-year amortization schedule to write off equipment already retired at the Port St. Joe and Blountstown offices. As of January 1, 1984, there were three **[*5]** years remaining on the recovery schedule, with a net balance of $812,540. Based on the staff's calculations, we believe that this amortization period should be shortened and the balance written off in one year, along with the historical deficit. It appears that the Company will be able to absorb the additional $812,540 in 1984 and still earn its allowed return on equity.

RETIREMENT OF ELECTROMECHANICAL CENTRAL OFFICE EQUIPMENT

Eleven of the thirteen offices operated by St. Joe contain step-by-step electromechanical equipment. The Company has plans to replace four of these step offices with digital switches over the next two years. The offices where the replacement will occur are located at Carrabelle, Tyndall, Apalachicola and The Beaches. The conversion to digital switches is necessary because of the Company's growth, the exhaustion of floor space and the enhancement in the quality of service that the new switches will provide. We agree with the staff that the Company's replacement plans appear to be prudent. We further agree with staff that the unrecovered balance of this central office equipment, $1,107,544, should be recovered on a 3-year recovery schedule **[*6]** as follows:

Total Unrecovered (1-1-84)	$1,107,544.00
Total Annual Expense	$ 369,181.00

Monthly Expense	$ 30,765.00

In 1984, the Company plans to make some additions to the electromechanical equipment contained in the four step offices scheduled for replacement. According to the information supplied by the Company, these additions will total some $187,170 for 1984. No additions are contemplated for 1985 or 1986. Since this equipment will be retained for use when the digital switches are in place, we conclude that no special recovery treatment for these additions is needed for the 1984-1986 period.

SUBMARINE CABLE

The Company's investment in submarine cable is expected to all be retired prior to the next represcription. The unrecovered investment of $15,060 should be recovered as a 3-year recovery schedule as follows:

Unrecovered Balance	$15,060.00
Annual Accrual	$ 5,020.00
Monthly Accrual	$ 418.33

ADJUSTMENT TO ACCOUNT 212.14, DEPRECIATION RESERVE FOR BUILDINGS

In 1983, the Company discovered that it had mistakenly included self-supporting towers in the Pole Lines account (241). According to the Uniform System of Accounts, these structures **[*7]** should have been included in Buildings (Account 212). To correct this mistake, the Company transferred tower investment of $46,219 to the Buildings account. However, in calculating the corresponding reserve to be transferred, the Company made an additional error of $13,216. The error occured because the Company first calculated the reserve as though the investment had been in Buildings and transferred that amount, $9,623, to the Buildings account. The total difference in depreciation expense that had accrued in Pole Lines, less the amount that was transferred, was then calculated and an adjustment by that amount, $13,216, was made, reducing the 1983 expense for Pole Lines rather than transferring the additional amount to Buildings. This had the effect of increasing rate base by $13,216. Since the investment had historically been in the Pole Lines account and had been depreciated at the rate of that account, it was not appropriate to adjust rate base in this manner. Accordingly, we find that the depreciation reserve for Buildings, Account 212.14, should be adjusted to increase the reserve by $13,216.

Now, therefore, in consideration of the above, it is

ORDERED by the Florida **[*8]** Public Service Commission that the depreciation reserves, rates and expenses of St. Joseph Telephone and Telegraph Company, be and the same are hereby adjusted and represcribed as set forth in the body of this order, and in the appended Attachments 1, 2, and 3. It is further

ORDERED that the provisions of this order, issued as proposed agency action, shall become final unless a petition pursuant to Rule 25-22.29, Florida Administrative Code, and in the form provided by Rule 25-22.36, Florida Administrative Code, is received by the Commission Clerk at his office at 101 East Gaines Street, Tallahassee, Florida, 32301, by the close of business on January 3, 1985. It is further

ORDERED that upon receipt of an appropriate petition regarding this proposed agency action, the Commission will institute further proceedings in accordance with Rule 25-22.36, Florida Administrative Code. It is further

ORDERED that after January 3, 1985, the Commission shall either issue notice of further proceedings, or an order acknowledging that the provisions of this notice have become final. It is further

ORDERED that if this order becomes final and effective on January 3, 1985, any party **[*9]** adversely affected may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission Clerk and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure. It is further

ATTACHMENT B

ORDERED that if this order becomes final and effective on January 3, 1985, any party adversely affected may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission Clerk and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure. **[*10]**

By Order of the Florida Public Service Commission, this 14th day of DECEMBER, 1984.

Attachment 1

ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY

		COMMISSION APPROVED RATES			
		AVERAGE	**FUTURE**		**REMAINING**
ACCOUNT		**REMAINING**	**NET**	**APPROPRIATE**	**LIFE**
NUMBER	**ACCOUNT DESCRIPTION**	**LIFE**	**SALVAGE**	**RESERVE**	**RATE**
		(Years)	(%)	(%)	(%)
	BUILDINGS				
212.00	Buildings - total				
212.10	Single Unit Switching	32.0	2.0	19.6	2.5
212.20	Office	29.0	8.5	19.9	2.5
212.30	Plant or warehouse	24.0	3.0	24.3	3.0
212.40	Sheds, other	23.0	-2.0	11.8	3.9
	CENTRAL OFFICE EQUIPMENT				
221.30	COE - Step (Remaining)	7.2	0.0	41.0	8.2
221.40	COE - Digital	11.9	5.0	10.0	7.1
221.50	COE - Carrier - Total				
221.51	COE - Carrier - Analog	8.1	0.0	36.8	7.8
221.52	COE - Carrier - Digital	9.0	15.0	24.7	6.7
221.53	COE - Carrier - other	3.3	30.0	34.3	10.8
221.59	COE - Carrier - Optics	10.0	0.0	0.0	10.0
221.60	COE - Microwave	8.3	0.0	27.0	8.8
	STATION EQUIPMENT				
231.10	Station App. -Embedded	4.5	10.0	@ 25.89	14.2
231.20	Station App. -Official	5.0	0.0	44.5	11.1
231.30	Station App. -Paystations	6.0	0.0	40.0	10.0
232.10	Station Conn. -Inside		10 Year Amortization		

ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY

		COMMISSION APPROVED RATES			
		AVERAGE	FUTURE		REMAINING
ACCOUNT		REMAINING	NET	APPROPRIATE	LIFE
NUMBER	ACCOUNT DESCRIPTION	LIFE	SALVAGE	RESERVE	RATE
234.10	Large PBX -Embedded	3.5	5.0	@ 33.17	17.7
234.20	Large PBX -Official	7.5	10.0	5.3	11.3
	OUTSIDE PLANT				
241.00	Pole Lines	13.0	-30.0	49.4	6.2
242.10	Aerial Cable	13.9	-25.0	48.6	5.5
242.15	Aerial Cable - Drop & Block				# 4.9
242.20	Underground Cable	29.0	-5.0	7.4	3.4
242.30	Buried Cable - Total				
242.31	Buried Cable - Filled	24.0	-6.0	12.4	3.9
242.32	Buried Cable - Non-Filled	9.2	-6.0	40.7	7.1
242.33	Buried Cable - Fiber Optic	20.0	-5.0	0.0	5.3
242.34	Buried Cable - Drop & Block				# 4.9
243.00	Aerial Wire - New Additions	10.0	-5.0	0.0	10.5
242.40	Submarine Cable		Recovery Schedule		
244.00	Underground Conduit	47.0	-2.0	8.0	2.0
	GENERAL PLANT				
261.10	Furniture & Office Equipment				
261.11	Furniture	17.8	5.0	@ 22.70	4.1
261.12	Office Equipment	6.8	5.0	@ 50.69	6.5
261.20	Computer Equipment	5.3	5.0	23.1	13.6
264.10	Vehicles - Total				
264.11	Cars	2.6	33.0	37.9	11.2
264.12	Light Trucks	2.4	33.0	40.1	11.2
264.13	Heavy Trucks	6.1	18.0	32.0	8.2
264.20	Tools	8.2	5.0	@ 62.83	3.9
264.30	Trailers	3.8	10.0	55.8	9.0
264.40	Heavy Equipment	6.0	10.0	45.0	7.5

[*11]

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Attachment 2

ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY

COMMISSION RESTATED RESERVE TO BE BROUGHT FORWARD BY ANNUAL ACTIVITY *

ACCOUNT DESCRIPTION		
212.11	Single Unit Switching	$ 159,139
212.12	Office	252,224
212.13	Plant & Warehouse	57,532
212.14	Sheds, Other	92,483
221.30	COE - Step (Remaining)	1,295,713
221.40	COE - Digital	499,815
221.51	COE - Carrier-Analog	573,865
221.52	COE - Carrier-Digital	337,107
221.53	COE - Carrier-Other	339,142
221.60	COE - Microwave	450,387
231.20	Station App. - Official	72,229
231.30	Station App. - Paystations	96,762
234.20	Large PBX - Official	3,828
241.00	Pole Lines	246,080
242.10	Aerial Cable	473,214
242.20	Underground Cable	14,299
242.31	Buried Cable - F	891,934
242.32	Buried Cable - NF	1,254,668
243.00	Aerial Wire	0
244.00	Underground Conduit	36,867
261.20	Computer Equipment	165,210
264.11	Cars	73,776

[@] @ -Actual Reserve,

-Composite of Aerial Cable and Buried Cable Account Rates

[*] Excluded from the netting of the reserve deficits are embedded Station Apparatus, Station Connections and PBX, as well as Special Military ADCCS Equipment, Drop and Block, Furniture, Office Equipment, Tools, and equipment on the recovery schedules for Step Central Office Equipment and Submarine Cable.

264.12	Light Trucks	142,038
264.13	Heavy Trucks	23,098
264.30	Trailers	6,358
264.40	Heavy Equipment	56,525
TOTAL		$7,614,293

[*12]

Book Reserve	= $6,458,078
Less: Theoretical Reserve Based on Current Rates	= $6,987,080
Historic Deficit	= $ 529,002
Theoretical Reserve Based on Current Rates	= $6,987,080
Less: Theoretical Reserve Based on Commission Approved Rates	= $7,614,293
Prospective Deficit	= $ 627,213

Attachment 3

ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY

RECOVERY SCHEDULES

Equipment Description	**Unrecovered Investment ($)**	**Amortization Period (Years)**	**Annual Expense ($)**
Existing C.O.E. Equipment (Port St. Joe and Blountstown Offices)	$ 812,540	1	$812,540
Steps Equipment to be Retired in 1984-1986 (Carrabelle, Tyndall, Apalachicola and The Beaches)	$1,107,544	3	$369,181
Submarine Cable	$ 15,060	3	$ 5,020

ATTACHMENT B

FL Public Service Commission Decisions

End of Document

1985 Fla. PUC LEXIS 299

Florida Public Service Commission

September 11, 1985

DOCKET NO. 840049-TL; ORDER NO. 14929, 85 FPSC 80

FL Public Service Commission Decisions

Reporter
1985 Fla. PUC LEXIS 299 *

In re: Application of General Telephone Company of Florida for new depreciation rates

Core Terms

depreciate, switch, yrs, electronic, salvage, retirement, cable, per year, metallic, fiber, month, radio, notice, strand, toll, underground cable, remaining life, conduit, plant, bury, electromechanical, telephone, deficit, install, block, drop

Panel: ; The following Commissioners participated in the disposition of this matter: JOHN R. MARKS, III, Chairman; JOSEPH P. CRESSE, GERALD L. GUNTER, MICHAEL MCK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER REPRESCRIBING DEPRECIATION RATES

BY THE COMMISSION:

Notice is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for formal proceeding pursuant to Rule 25-22.29, Florida Administrative Code.

This proceeding was initiated on February 9, 1984, when General Telephone Company of Florida (Gentel or Company) submitted its depreciation study for our review. Pursuant to Florida Administrative Code Rule 25-4.175, telephone companies are required to file a depreciation study with the Commission at least once every three years. Our last review of Gentel's depreciation study took place in 1981 and resulted in new depreciation rates being put into effect in December 1981. At that time we found it appropriate to implement a change from whole life to remaining life depreciation methodology and we also prescribed amortization **[*2]** schedules addressing negative reserve components of electromechanical switchers. In the Company's concurrent rate case we also prescribed vintage group rates for new additions to plant.

Since Gentel's last depreciation represcription there have been substantial developments in the areas of technology and competition which we believe should be reflected in new depreciation rates. We believe that it is imperative that we address the effects of these pressures now, notwithstanding the current controversy which has arisen over the Federal Communications Commission preemption of intrastate depreciation rates. This Commission is actively participating in proceedings before the United States Supreme Court where the issue of

 ATTACHMENT B

FCC preemption will finally be resolved. However, in view of the age of this docket and the uncertainties of the date of the Court's final decision, we believe it is our duty and in the best interest of the Company and the ratepayers to move forward with represcription of the Company's intrastate depreciation rates. The specific rates and recovery schedules are discussed in the body of this order and in the attached Schedules 1 - 5.

The Company has asked for a **[*3]** May 1, 1985 implementation date for the new rates. However, we believe that it would be appropriate for the new rates to be effective January 1, 1985. The same effective date was approved by the FCC in the Company's depreciation proceedings before that agency.

Reserve Deficit

Based on the Staff's calculations we have determined that Gentel's net reserve deficit amounts to some $32,138,000. This amount was derived by calculating a reserve imbalance by depreciable account or sub-account for all investments except those associated with electromechanical and electronic analog switchers planned for retirement during 1985-1987, those associated with potential investments in plant to be stranded by 1987 and those associated with Drop and Block Wire. The various reserve imbalances were then netted to a bottom line.

As a result of the netting of the reserve imbalances each associated account or sub-account should be restated at the theoretically correct position, as shown in Schedule 1 attached to this order. Rates for new additions will be the same as for embedded plant except for the electromechanical, electronic and digital switching accounts. These accounts **[*4]** are measured against the average date of final retirement, and new additions have been given a separate rate in accord with their resultant shortened lives. Those rates are set out on Schedule 2 attached to this order.

We believe that it is in the interest of both Gentel's customers and its stockholders that the Company's $32,138,000 deficit be written off in as short a time as practicable. In this case we find that a five-year period is appropriate. This results in an amortization amount of $6,427,600 per year or $535,633 per month. The Company shall create a separate subaccount in the accumulated depreciation reserve to reflect the amortization of this deficit. No further surpluses or deficits should be included in this subaccount without Commission approval.

Depreciation Rates and Recovery Schedules

The Staff has made a comprehensive review of Gentel's depreciation study and has recommended rates for the Company's intrastate operations. Based on the Staff's recommendation we find the appropriate depreciation rates and components are set forth on Schedule 3 attached to this order with the exception of special rates developed for short-lived electromechanical and local **[*5]** electronic analog switching additions. The rates for these short-lived additions are shown on Schedule 4 attached to this order. The treatment reflected in that schedule is designed to recover each year's additions over their composite remaining life.

The approved recovery schedules covering switchers being retired during the next three years and potential stranded investments are set forth on Schedule 5 attached to this order. These schedules reflects the period beginning January 1, 1985 and continuing through December 31, 1987.

Status Reports

In consideration of the recovery schedules recommended for near-term retirement of switchers and for stranded investments, we find that it would be appropriate to require the Company to submit quarterly status reports beginning January 1, 1986. With the phasing-out of installations there may be variations between actual and projected activity. Therefore, we believe that the Company should submit quarterly reports covering: 1) 1985-1987 electromechanical switching retirements; 2) 1985-1987 electronic analog switching retirements; and 3) stranded investments in each of the circuit, radio, buried cable, underground cable, **[*6]** and conduit accounts. These reports should show plant balances and activity as well as reserve balances and activity and should also list by changes in plans (such as retirement dates or lease agreements) or changes anticipated net salvage.

In consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that the depreciation rates set forth in the body of this order and on Schedules 1 through 5 attached to this order be and the same are hereby approved for General Telephone Company of Florida. It is further

ORDERED that the effective date of the new rates is January 1, 1985. It is further

ORDERED that the Company shall file quarterly reports as set forth in the body of this order. It is further

ORDERED that in the event this order becomes final as set forth below this docket shall be closed. It is further

ORDERED that this order will become effective on October 2, 1985 unless a petition for formal proceedings is received by October 1, 1985.

By ORDER of the Florida Public Service Commission this 11th day of September 1985.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), **[*7]** Florida Statutes (Supp. 1984), to notify parties of any administrative hearing or judicial review of Commission orders that may be available, as well as the procedures and time limits that apply to such further proceedings. This notice should not be construed as an endorsement by the Florida Public Service Commission of any request nor should it be construed as an indication that such request will be granted.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule 25-22.29, Florida Administrative Code. Any person adversely affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.29(4), Florida Administrative Code, in the form provided by Rule 25-22.36(7)(a) and (f), Florida Administrative Code. This petition must be received by the Commission Clerk at his office at 101 East Gaines Street, Tallahassee, Florida 32301, by the close of business on October 1, 1985. In the absence of such a petition, this order shall become effective October 2, 1985, as provided by Rule 25-22.29(6), Florida Administrative Code, and as reflected in a subsequent order. **[*8]**

If this order becomes final and effective on October 2, 1985, any party adversely affected may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission Clerk and the filing of a copy of the notice and filing fee with the Supreme Court. This filing must be completed within 30 days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Schedule 1

General Telephone Company of Florida

ACCOUNT		**1-1-85 RESTATED RESERVE BY ACCOUNT TO BE BROUGHT FORWARD BY ANNUAL ACTIVITY** ($000)
212	Buildings	
	Single-Unit Switching	8,978
	Multi-Unit Switching	1,957
	Plant Buildings	4,777

General Telephone Company of Florida

ACCOUNT		1-1-85 RESTATED RESERVE BY ACCOUNT TO BE BROUGHT FORWARD BY ANNUAL ACTIVITY
	Office Buildings	16,812
	Other Buildings, Towers, and	
	Leasehold Improvements	4,317
221	Central Office Equipment	
	Electromechanical/AMR	60,739
	Electronic Switching	
	Local	92,989
	Toll	91
	Other Electronic Boards	111
	Digital/AMR Switching	
	Local	5,794
	Toll	3,382
	Manual/Digital Toll	4,985
	Circuit and Circuit DDS	41,453
	Circuit Optical	122
	Radio and Radio DDS	12,074
231	Station Equipment	
	Network Terminating Equipment	3,594
	Subscriber Carrier Equipment	3,879
	TDD Equipment	8
234	Large PBX	
	Special PBX	3,156
235	Public Telephone Equipment	6,067
241	Pole Lines	5,036
241.1	Aerial Cable	
	Metallic	36,494
	Fiber	0
	Drop and Block	* 3,744

* Book Reserve

General Telephone Company of Florida

ACCOUNT		1-1-85 RESTATED RESERVE BY ACCOUNT TO BE BROUGHT FORWARD BY ANNUAL ACTIVITY
242.2	Underground Cable	
	Metallic	26,899
	Fiber	159
242.3	Buried Cable	
	Metallic	99,718
	Fiber	32
	Drop and Block	* 10,352
242.4	Submarine Cable	
	Metallic	1,771
	Fiber	1
243	Aerial Wire	2,787
244	Conduit	15,494
261	Furniture and Office Equipment	
	Office Furniture	966
	Office Machines	1,024
	Computer/Data Equipment	1,135
262	Official Telephones	9,909
	Official PBX	4,896
264	Motor Vehicles and OWE	
	Motor Vehicles	
	Passenger Cars	1,533
	Light Trucks	7,210
	Heavy Trucks	955
	Heavy Equipment	992
	Shop Equipment	106
	Other Work Equipment	3,122

General Telephone Company of Florida

ACCOUNT	1-1-85 RESTATED RESERVE BY ACCOUNT TO BE BROUGHT FORWARD BY ANNUAL ACTIVITY
Recovery Schedules:	
Electromechanical/AMR rets. (1985 - 1987)	* 118,334
Electronic Analog Switching rets. (1985 - 1987)	* 4,036
Stranded Investment:	
Radio	* 4,603
Circuit	* 11,541
Buried Cable	* 1,095
Underground Cable	* 400
Conduit	* 287

[*9]

Schedule 2

DEPRECIATION RATES FOR

ADDITIONS TO SWITCHING

INSTALLATIONS

DEPRECIATION RATES FOR ADDITIONS TO

ELECTROMECHANICAL

INSTALLATIONS SCHEDULED FOR

RETIREMENT AFTER 1987

	Remaining Life	Net Salvage	Depreciation Rate
1985	3.9 yrs.	3%	24.9%
1986	3.3 yrs.	3%	29.4%
1987	2.9 yrs.	2%	33.8%

DEPRECIATION RATES FOR ADDITIONS TO

LOCAL ANALOG SWITCHING

INSTALLATIONS SCHEDULED FOR

RETIREMENT AFTER 1987

	Remaining Life	Net Salvage	Depreciation Rate
1985	7.2 yrs.	0%	13.9%
1986	6.8 yrs.	0%	14.7%
1987	6.3 yrs.	0%	15.9%

DEPRECIATION RATES FOR

ADDITIONS TO EXISTING DIGITAL SWITCHERS

LOCAL SWITCHERS

	Remaining Life	Net Salvage	Depreciation Rate
1985	12.5 yrs.	4%	7.7%
1986	11.8 yrs.	6%	8.0%
1987	11.1 yrs.	6%	8.5%

DEPRECIATION RATES FOR

ADDITIONS TO EXISTING DIGITAL SWITCHERS

TOLL SWITCHERS

	Remaining Life	Net Salvage	Depreciation Rate
1985	13.0 yrs.	0%	7.7%
1986	12.2 yrs.	0%	8.2%
1987	11.5 yrs.	0%	8.7%

NEW DIGITAL INSTALLATIONS

GOING INTO SERVICE

DURING 1985 - 1987

LOCAL SWITCHERS

Average Service Life	Net Salvage	Depreciation Rate
15 yrs.	(5)%	7.0%

[*10]

Schedule 3

General Telephone Company of Florida

Depreciation Rates and Components

ACCOUNT		COMMISSION APPROVED EFFECTIVE JANUARY 1, 1985 AVERAGE REMAINING LIFE (Years)	FUTURE NET SALVAGE (%)	APPROPRIATE RESERVE ** (%)	REMAINING LIFE RATE (%)
212	Buildings				
	Single-Unit Switching	23	0	24.10	3.3
	Multi-Unit Switching	29	0	27.50	2.5
	Plant Buildings	21	0	30.70	3.3
	Office Buildings	42	0	24.40	1.8
	Other Buildings, Towers, and Leasehold Improvements	18.4	0	39.30	3.3
221	Central Office Equipment				
	Electromechanical/AMR	4.7	(3)	53.65	10.5
	Electronic Switching				
	Local	7.8	0	33.7	8.5
	Toll	15.1	0	19.97	5.3
	Other Electronic Boards	12.4	1	7.24	7.4
	Digital/AMR Switching				
	Local	13.2	5	11.84	6.3

** Denotes Staff Calculated theoretical reserve.

General Telephone Company of Florida

Depreciation Rates and Components

COMMISSION APPROVED EFFECTIVE

JANUARY 1, 1985

ACCOUNT		AVERAGE REMAINING LIFE	FUTURE NET SALVAGE	APPROPRIATE RESERVE **	REMAINING LIFE RATE
	Toll	13.7	5	10.06	6.2
	Manual/Digital Toll	14	1	29.0	5.0
	Circuit and Circuit DDS	11.2	5	16.6	7.0
	Circuit Optical	9.2	0	8.0	10.0
	Radio and Radio DDS	6.5	(3)	51.0	8.0
231	Station Equipment				
	Network Terminating Equipment	4.1	4	48.03	11.7
	Subscriber Carrier Equipment	4.3	4	45.26	11.8
	TDD Equipment	4.7	4	40.54	11.8
234	Large PBX				
	Special PBX	4.5	2	45.8	11.6
235	Public Telephone Equipment	4.0	4	48.8	11.8
241	Pole Lines	20	(50)	30.0	6.0
241.1	Aerial Cable				
	Metallic	17.5	(20)	41.25	4.5
	Fiber	19.6	(15)	1.32	5.8
	Drop and Block	20	0		5.0
242.2	Underground Cable				
	Metallic	27	(5)	15.9	3.3
	Fiber	18.9	(5)	4.83	5.3
242.3	Buried Cable				
	Metallic	23	(5)	24.5	3.5
	Fiber	19.1	(5)	3.77	5.3

General Telephone Company of Florida

Depreciation Rates and Components

		COMMISSION APPROVED EFFECTIVE JANUARY 1, 1985			
		AVERAGE REMAINING	FUTURE NET	APPROPRIATE	REMAINING LIFE
ACCOUNT		LIFE	SALVAGE	RESERVE **	RATE
	Drop and Block	20	0		5.0
242.4	Submarine Cable				
	Metallic	17.7	(5)	37.74	3.8
	Fiber	19	(5)	4.3	5.3
243	Aerial Wire	7.6	(30)	46.4	11.0
244	Conduit	51	(7)	15.2	1.8
261	Furniture and Office Equipment				
	Office Furniture	17.6	3	10.76	4.9
	Office Machines	7.3	0	42.33	7.9
	Computer/Data Equipment	5.6	1	15.0	15.0
262	Official Telephones	3.4	4	52.48	12.8
	Official PBX	5.3	2	34.4	12.0
264	Motor Vehicles and OWE				
	Passenger Cars	4.4	25	32.32	9.7
	Light Trucks	3.0	25	46.8	9.4
	Heavy Trucks	5.8	10	47.66	7.3
	Heavy Equipment	4.6	10	56.42	7.3
	Shop Equipment	13.6	8	21.28	5.2
	Other Work Equipment	7.1	5	33.94	8.6
	Recovery Schedules:				
	Electromechanical/AMR rets. (1985 - 1987)	3	year recovery schedule		
	Electronic Analog Switching	3	year recovery schedule		

ATTACHMENT B

General Telephone Company of Florida

Depreciation Rates and Components

	COMMISSION APPROVED EFFECTIVE JANUARY 1, 1985			
	AVERAGE	**FUTURE**		**REMAINING**
	REMAINING	**NET**	**APPROPRIATE**	**LIFE**
ACCOUNT	**LIFE**	**SALVAGE**	**RESERVE** **	**RATE**
rets. (1985 - 1987)				
Stranded Investment:				
Radio	3	year recovery schedule		
Circuit	3	year recovery schedule		
Buried Cable	3	year recovery schedule		
Underground Cable	3	year recovery schedule		
Conduit	3	year recovery schedule		

[*11]

Schedule 4

Depreciation Rates For

Short-Lived Electromechanical

Switching Additions

	Remaining Life	**Net Salvage**	**Depreciation Rate**
	(years)	(%)	(%)
1985	2.1	4	45.7
1986	1.3	4	73.8
1987	0.5	3	194.0

Depreciation Rates For

Short-Lived Local Electronic Analog Switching Additions

	Remaining Life (years)	Net Salvage (%)	Depreciation Rate (%)
1985	1.6	23.0	48.1
1986	1.1	20.0	72.7

Schedule 5

Recovery Schedules

Effective January 1, 1985, Continuing through December 31, 1987

1. Electromechanical/ AMR 1985-1987 retirements:

Investment =	$180,406,996
Less reserve =	118,334,388
Less 2.5% salvage =	4,510,175
Unrecovered investment	$ 57,562,433
Expenses per year	$ 19,187,478
Expenses per month	$ 1,598,956

2. Electronic Analog Switching 1985-1987 retirements:

Investment =	$11,480,689
Less reserve =	4,036,027
Unrecovered Investment =	$ 7,444,662
Expenses per year	$ 2,481,554
Expenses per month	$ 206,796

3. Stranded Investment:

Radio

Investment =	$11,141,042
Less reserve =	4,602,882
Less 20% salvage =	2,228,208
Unrecovered Investment	$ 4,309,952
Expenses per year	$ 1,436,651
Expenses per month	$ 119,721

Circuit

Investment =	$70,432,750
Less reserve =	11,541,115
Less 20% salvage =	14,086,550
Unrecovered investment	$44,805,085
Expenses per year	$14,935,028
Expenses per month	$ 1,244,586

Buried Cable

Investment =	$1,507,612
Less Reserve =	1,094,557
Unrecovered investment	$ 413,065
Expenses per year	$ 137,688
Expenses per month	$ 11,474

Underground Cable

Investment =	$640,330
Less Reserve =	400,231
Unrecovered Investment	$240,099
Expenses per year	$ 80,033
Expenses per month	$ 6,669

Conduit

Investment =	$821,584
Less Reserve =	287,235
Unrecovered Investment	$534,349
Expenses per year	$178,116
Expenses per month	$ 14,843

[*12]

FL Public Service Commission Decisions

End of Document

1986 Fla. PUC LEXIS 72

Florida Public Service Commission

December 16, 1986

DOCKET No. 851110-TL; ORDER NO. 16963, 86 FPSC 226

FL Public Service Commission Decisions

Reporter
1986 Fla. PUC LEXIS 72 *

In re: Application of Central Telephone Company of Florida for New Depreciation Rates

Core Terms

depreciate, retirement, technology, digital, salvage, recommend, switch, has, unrecovered, switchers, fiber, amortize, cable, radio, companies, monthly, plant, deficit, notice, reuse, cost, telecommunication, subaccounts, telephone, estimate, annual, optic, carrier, install, staff

Panel: ; The following Commissioners participated in the disposition of this matter: JOHN R. MARKS, III, Chairman; GERALD L. GUNTER, JOHN T. HERNDON, KATIE NICHOLS, MICHAEL McK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING NEW DEPRECIATION RATES AND ADJUSTMENT OF DEPRECIATION RESERVE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission of its intent to approve Central Telephone Company of Florida's (Centel) application for new depreciation rates and adjustment of depreciation reserves pursuant to Sections 350.127 and *364.03, Florida Statutes (1985)*, and Rule 25-4.175, Florida Administrative Code (F.A.C.). This action is preliminary in nature and will become final unless a person whose interests are adversely affected files a petition for formal proceeding pursuant to Rule 25-22.29, F.A.C.

INTRODUCTION

Rule 25-4.175(7), F.A.C., requires telephone companies to periodically file a comprehensive depreciation study at least once every three years. In keeping with the requirements of this rule, Centel filed a depreciation study (the Study) on December 30, 1985. **[*2]** Before this filing, our last comprehensive review of Centel's depreciation rates was performed in 1983. In the three years since the last review, there have been substantial changes in technology and competition, indicating a need for prescribing new rates where appropriate. Moreover, Centel acquired the Florida facilities of Continental Telephone Company of the South (Contel) during 1985. The Study reflects this merger, embodying combined investments and reserves, and represents a comprehensive review of all classes of equipment.

IMPLEMENTATION DATE FOR NEW RATES

Centel requested a January 1, 1986 implementation date for its newly-prescribed depreciation rates. All data and calculations submitted in support of the Study abut this date. We believe this to be an appropriate effective date and will approve the requested implementation date.

RESERVE ADJUSTMENTS

As part of our review of the Study, we have examined the reserve position of each account. The following reserve transfers will be approved in order to correct the major imbalances found:

	1-1-86	**CALCULATED**		
	BOOK	**THEORETICAL**		**RESTATED**
ACCOUNT	**RESERVE**	**RESERVE**	**TRANSFER**	**RESERVE**
COE Circuit-Other	$9,368,767	$3,211,856	$ (6,156,911)	$3,211,856
COE Circuit-Digital	3,678,737	5,089,675	1,410,938	5,089,675
Buried Cable-Non Filled	3,995,627	6,162,079	2,166,452	6,162,079
Other CMU Equip-Tel	411,657	198,070	(213,587)	198,070
Passenger Cars	168,836	177,778	8,942	177,778
Light Trucks	910,780	697,919	(212,861)	697,919
Heavy Trucks	4,020	119,048	115,028	119,048
Prospective Reserve Deficit	(9,808,678)	0	2,882,065	(6,926,613)

[*3]

As a result of our approving the above transfers, each listed account's reserve will be brought more nearly in line with its calculated theoretical position.

DEPRECIATION RATES

As a result of our comprehensive review of the Study, we will adopt our Staff's recommended depreciation rates, recovery schedules and resultant expenses contained in Attachments 1 and 2, labelled "Comparison of Depreciation Rates and Components" and "Comparison of Depreciation Expenses," respectively, which are appended hereto. This action will result in an approximate increase in annual expenses of about $4.6 Million, on a total company basis, when the rates are applied to investments as of January 1, 1986. Attachment 1 provides a comparison of the Current, Company Proposed and Staff Recommended rate components of lives and salvages. Those figures identified as Current Rates thereon represent a composite of the rates prescribed for Centel and Contel. Attachment 2 shows the resultant estimated expenses, including those from recovery schedules authorized below. Investments and reserves shown there represent the combined assets of Centel and Contel on January 1, 1986.

We find that the rates to **[*4]** be prescribed here are justified by the information received in this proceeding. However, we are concerned that this action may not sufficiently address the total capital recovery needs of Centel. The Study appeared, in part, to address statistics rather than to identify deficits and shortfalls. With the rapid changes taking place in the telecommunications industry, gaining an understanding of the needs and pressures facing an individual company should take precedence in such a study over statistical analysis. We encourage Centel to react as quickly as possible to the impact that new technologies may have on its existing plant. Upon review of Centel's switching planning, we deem the 1986-1988 retirements and interim additions proposed in the Study to be prudent.

RECOVERY SCHEDULES

1. Buildings. Two buildings housing radio equipment are identified by Centel as becoming stranded in 1990 due to AT&T Communications of the Southern States, Inc.'s (ATT-C) placing fiber optic facilities that will bypass eight microwave radio routes. These buildings are located at Forest Beach and Defuniak Springs. Centel plans to dismantle and retire the radio tower located at the Forest **[*5]** Beach building and then reuse the building as a remote switching facility. The Defuniak Springs building is located in a rural, low-growth area, and Centel has no plans for its reuse. The investment and associated reserve of these retirements, the Forest Beach tower and the Defuniak Springs building, are $704,155 and $208,582, respectively. Using Centel estimates of net salvage of negative $4,000 results in an unrecovered amount of $499,573. We will approve a recovery schedule that allows this amount to be recovered over a four-year period beginning January 1, 1986, and continuing through December 31, 1989. This schedule will provide for annual expenses of $124,893 or monthly expenses of $10,408.

2. Electromechanical Switching Retirements. Centel has two existing recovery schedules that address unrecovered electromechanical switching investments which were retiring during the 1983-1985 period, one for Centel and another for Contel. These schedules were established during each company's last depreciation review in 1983 and call for recovery periods of 5 and 3 1/2 years, respectively.

According to Centel's current planning, all remaining electromechanical switchers will **[*6]** be replaced by the end of 1987. High maintenance costs, extensive floor space requirements, high trunking costs, lack of custom-calling features and extensive rearrangements to provide growth have led to their replacement by digital switchers throughout the telecommunications industry.

At this time, with all remaining switchers planned for retirement by year-end 1987, Centel has proposed that the unrecovered investments in the two existing schedules be combined with the remaining unrecovered investments slated for retirement. This would have a smoothing effect on expenses but would defer recovery of those investments that retire earlier than the schedules' amortization periods. In the past, our Staff has recommended placing all near-term electromechanical retirements on one schedule to be amortized over a matching period of time. In this case, our Staff recommended recovery of 1986 retirements during 1986 and recovery of 1987 retirements during 1986 and 1987. We will adopt this approach because it more closely matches the recovery period to the remaining life of these investments.

According to Centel's data, the investment and reserve of those installations planned for retirement **[*7]** in 1986 are $17,669,328 and $11,102,275, respectively. Assuming a negative 2% net salvage, the amount of $6,920,440 would be unrecovered and should be written-off in 1986. The investment, inclusive of budgeted short-lived additions, and reserve for those installations planned for retirement in 1987 are $3,423,725 and $2,852,823, respectively. Also assuming a negative 2% net salvage for the 1987 investments, an unrecovered amount of $639,377 remains to be written-off over two years beginning January 1, 1986, and continuing through December 31, 1987. Combining these two actions produces monthly expenses of about $26,641 or annual expenses of about $319,688. The expense of this schedule for each month should be determined by dividing the net unrecovered plant for that month by the number of months remaining in the amortization period. This will assure full recovery of short-lived additions over their lives.

3. Radio Equipment - Stranded Investment. As discussed above, ATT-C is installing fiber optic facilities that will bypass radio routes, thereby stranding eight microwave radio locations. The investment and reserve at the beginning of 1986 were $8,877,150 and $4,275,678, **[*8]** respectively. Centel foresees no potential for reuse of these facilities due to the increasing availability of digital and fiber optic technologies; therefore, we will approve a four-year amortization schedule to recover their remaining cost of $4,601,472. The term of this schedule will be from January 1, 1986, until December 31, 1987. The schedule's annual expenses will be $1,150,368 or $95,864 monthly.

4. Electronic Digital Switching Retirements. One VIDAR digital switch and two remotes are currently in operation in the properties acquired from Contel. This type of digital switch is no longer being manufactured and all additions and spare parts can now be obtained from used-equipment dealers only. According to Centel's current plans, this equipment is due to exhaust by year-end 1987. The associated investment and reserve are $1,368,137 and $390,268, respectively. Centel estimates salvage of negative $17,400, and thus the unrecovered amount is $995,269. We will approve a two-year recovery schedule of this unrecovered cost to match the recovery period to the remaining service life, commencing January 1, 1986, and continuing through December 31, 1987. It will result **[*9]** in annual expenses of $497,635 or monthly expenses of $41,470.

5. Minor Official Telephone Equipment. This minor equipment investment represents the embedded portion of the official telephone and PBX subaccounts relating to items costing less than $200 and no longer being capitalized. This equipment is currently being depreciated at the same rate as its related subaccounts. Centel has proposed a three-year amortization period for the unrecovered investment. Because the unrecovered amount is only $38,975, we will direct that this amount be written-off in 1986.

6. Historic Reserve Deficit. As part of the 1983 depreciation review for Contel, a historic reserve deficit of $555,000 was ordered to be amortized over a period of five years. This amount has now decreased to $277,500 and, under the currently-approved schedule, will be fully amortized by July 1, 1988. Since this deficiency relates to plant already retired, we will approved writing-off this remaining amount during 1986.

7. Prospective Reserve Deficit. As part of the 1983 depreciation reviews, prospective reserve deficits of $12,059,385 and $659,100 were found for Centel and Contel, respectively. Each **[*10]** is currently being amortized over 13-year periods that began on January 1, 1983, for Centel and on July 1, 1983, for Contel. As of January 1, 1986, the total amount remaining to be amortized was $9,808,678. We ordered above a reserve transfer of $2,882,065 from the surplus existing in the analog circuit account to reduce this remaining deficiency to $6,926,613. We will approve retaining the currently-approved annual expenses of $978,300 until the balance is recovered, which effectively reduces the remaining amortization period from 10 years to 7 years and 1 month.

ANALYSIS OF ACCOUNTS

BUILDINGS AND CENTRAL OFFICE EQUIPMENT:

The switching, circuit and radio accounts are feeling the impacts of optic, digital and cellular technologies. Our comments about the impact of these advancing technologies on Centel's depreciation rates are reported below by account.

1. Buildings. This account was divided into four separate building subcategories in 1984; however, our rules now provide for five subcategories, and these are reflected in our Staff's recommendations contained within Attachments 1 and 2. The rates recommended by our Staff and adopted here for these different **[*11]** groups are based on industry estimates for similar structures.

2. Radio (Remaining Investments). Centel Cellular Company, an independent subsidiary of Centel's parent Centel Corporation, has been awarded a license to begin operating a cellular communications facility in the Tallahassee area in 1987. According to Centel, this new activity will not greatly affect its existing mobile radio service because of the large number of customers waiting for mobile service and the rate differential between its mobile service and the future cellular service. We find that our Staff's recommendations are based on the current planning for these radio routes, and we will adopt them. However, Centel is ordered to monitor this account closely in the future for any impact from the new technology.

3. Circuit-Other. This equipment will be replaced on an as-needed basis rather than on a technological basis. For this reason, we find the results of the statistical analysis submitted by Centel to be reasonable and appropriate. We will approve a net salvage factor based on the most recent experience of this account. As discussed above, this account has a reserve surplus of $6,156,911 which **[*12]** will be transferred to offset deficits in other accounts. At the time of the last depreciation review, it was thought that all analog circuits would be retired in connection with

the move to digital switching. We have since learned that some analog carrier is not subject to technological obsolescence, and thus this equipment will not be expected to retire with the analog switchers.

4. Circuit-Digital. We have received reports from other telecommunications companies that digital circuit equipment is being retired upon retirement of the electromechanical office due to circuit capabilities now being inherent in the digital switch. According to Centel, the digital carrier being removed as a result of the replacement of offices is being reused in other areas and current plans are to continue doing so in the future. These carrier systems are being reused for subscriber carrier services, private line facilities and interfacing with interexchange carriers that are offering services in Centel's serving areas. This implies a short life with a high reuse salvage value. Recent salvage experience has averaged around 50%. In light of current reuse being expected to continue in the **[*13]** future, we will approve this net salvage factor.

5. Optic Electronics. Optical terminating equipment and multiplexing equipment making up fiber optic systems represent a new technology that will increase in investment size as more of this technology is deployed. This investment is currently being accounted for as part of the digital circuit equipment account and Centel proposes that it be depreciated at the same rate as appropriate for analog circuit equipment. Our depreciation subcategorization rules call for establishment of new subcategories comprised of new viable technologies. We will approve a separate depreciation rate for this investment.

6. Electronic Analog Switching. Current Centel plans are to retire the one automatic electronic analog switch and its associated equipment in this account in 1993 rather than around 1997 as originally anticipated. No additions are planned for this switcher because all growth will be served from digital remote line modules. We will approve our Staff's recommendations, which are based on this current planning submitted by Centel.

7. Digital Switching. According to Centel, the remaining switchers not planned for retirement **[*14]** during the next two years are flexible enough to be upgraded. We have also received reports from other telecommunications companies that processors are being retired due to this upgrading and that certain portions of the hardware investment is thus subject to a retirement pattern faster than the interim rate normally expected. Centel, both in the 1983 study as well as in this current study, stated that for their switchers this is not the case. Yet, we remain concerned that appropriate recovery is not being provided for these investments due to lack of information, and we direct Centel to monitor this account. We will approve our Staff's recommendations that are based on a 20-year life span with a 1% interim retirement rate for the toll switchers and 2% for local. While the above-discussed factors are appropriate for the embedded investments, they are not appropriate for any new additions planned for these switchers. We will approve a life of 13.8 years with a 5% net salvage, resulting in a 6.9% depreciation rate, to be applied to additions to the toll digital switcher. For additions to the local digital switchers, we will approve a life of 13.4 years with a 5% net salvage, resulting **[*15]** in a 7.1% depreciation rate. Moreover, during the 1986-1988 period, Centel plans to install fourteen new digital machines, and for this equipment, we will approve a 5.6% depreciation rate, computed by using a 17.1-year life with 5% net salvage.

STATION EQUIPMENT:

We are concerned that Centel may not be reacting as quickly as necessary to the potential impact of the changing environment of paystation equipment. Our approval of competitive pay telephone service as well as the introduction of "smart" pay telephones are factors that other telecommunications companies are recognizing as affecting the life of existing public telephone equipment. The impact of vandalism on depreciable life is another factor which should be considered. We will adopt our Staff's recommendations, which give recognition to the impact of these factors.

OUTSIDE PLANT:

The Outside Plant accounts are feeling the impact of fiber technology. Centel currently has no separate depreciation rates for this new technology. The cost of fiber has decreased to the point that, in some cases such as trunk and feeder routes, growth in service can be provided less expensively by installing fiber rather than **[*16]** copper. While Centel provided the investments and reserves for the fiber cable subaccounts, it has proposed that each be assigned the same rate as proposed for the associated metallic cable accounts. Our Staff recommended that these investments be separately maintained with their own depreciation rate. Recognizing that, in the past, life estimates for new technologies have tended to be overestimated, we will approve a 20-year life factor until some experience is developed. Additionally, since this investment is expected to grow significantly during the next three years, we will approve a whole life rate. This action is predicated on the assumption that the relative low age of the investment will result in the average service life and average remaining life approximately being the same during this period.

We find troubling Centel's proposed increase in life factors for underground cable. Other telecommunications companies have reported threats to this account, especially to the trunk and feeder investments, from the new fiber technology. Yet, Centel's proposals do not consider the impact of fiber but are based instead on statistical analysis which we deem to be inappropriate **[*17]** under current conditions. Accordingly, we will adopt our Staff's recommendations recognizing some impact by fiber technology.

Throughout Florida, air-core buried cable has been experiencing serious maintenance problems and much shorter lives than the jelly-filled cable. Centel's life proposals are the result of analyzing the total buried cable account with its mix of jelly-filled and air-core types of cable. We believe that different lives should be assigned to these separate types of cable because they are dissimilar in maintenance and life characteristics. We will adopt a shorter life than proposed by Centel for the air-core cable due to its inherent maintenance problems and a life for the jelly-filled cable that is longer than proposed.

The bookings of retirements, gross salvage and cost of removal in the Outside Plant accounts cause us some concern. We plan to have these accounts audited and any necessary corrections made before Centel's next depreciation study is undertaken. At this time, we will essentially retain the salvage values that are currently-prescribed for Centel.

GENERAL PLANT:

We find that the General Plant accounts are in line with industry estimates. **[*18]** The motor vehicle subaccounts were established in 1983, and based on the data submitted in the Study, it appears that problems were encountered in prorating the reserve to each subaccount. We will adopt our Staff's recommended reserve transfers between these subaccounts in order to bring each account more in line with its calculated theoretical position.

Now, therefore, in consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that depreciation reserve accounts of Central Telephone Company of Florida, its depreciation rates, and its depreciation expenses are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the schedules appended this Order.

By ORDER of the Florida Public Service Commission, this 16th day of DECEMBER, 1986.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes (1985), to notify parties of any administrative hearing or judicial review of Commission orders that may be available, as well as the procedures and time limits that apply to such further proceedings. This notice should not **[*19]** be construed as an endorsement by the Florida Public Service Commission of any request nor should it be construed as an indication that such request will be granted.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule 25-22.29, Florida Administrative Code. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.29(4), Florida Administrative Code, in the form provided by Rule 25-22.36(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting at his office at 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on January 5, 1987. In the absence of such a petition, this order shall become effective January 6, 1987, as provided by Rule 25-22.29(6), Florida Administrative Code, and as reflected in a subsequent order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period. **[*20]**

If this order becomes final and effective on January 6, 1987, any party adversely affected may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Director, Division of Records and Reporting and the filing of a copy of the notice and filing fee with the Supreme Court. This filing must be completed within 30 days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT 1

[TABLE OMITTED]

ATTACHMENT 2

[TABLE OMITTED]

FL Public Service Commission Decisions

End of Document

Florida Public Service Commission

August 24, 1987

DOCKET NO. 861618-TL; ORDER NO. 18029, 87-8 FPSC 260

FL Public Service Commission Decisions

Reporter
1987 Fla. PUC LEXIS 596 *

In re: Southern Bell Telephone and Telegraph Company's Depreciation Study for 1987

Core Terms

depreciate, cable, metallic, toll, amortize, deficit, salvage, telephone, recommend, wire, fiber, company, aerial, staff, telegraph, radio, carrier, install, was, plant, calculate, switchers, electronic, intrastate, network, embed, optic, bury, host, retirement

Panel: ; The following Commissioners participated in the disposition of this matter: KATIE NICHOLS, Chairman; THOMAS M. BEARD; GERALD L. GUNTER; JOHN T. HERNDON; MICHAEL McK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING NEW DEPRECIATION RATES, RECOVERY SCHEDULES AND ADJUSTMENT OF DEPRECIATION RESERVE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission of its intent to approve Southern Bell Telephone and Telegraph Company's (Bell's) application for new depreciation rates, recovery schedules and adjustment of depreciation reserves pursuant to Sections 350.127 and *364.03, Florida Statutes (1985)*, and Rule *25-4.0175, Florida Administrative Code*. This action is preliminary in nature and will become final unless a person whose interests are adversely affected files a petition for formal proceeding pursuant to Rule *25-22.029, Florida Administrative Code*.

INTRODUCTION

Rule 25-4.0175(7) requires telephone companies to periodically file a comprehensive depreciation study at **[*2]** least once every three years. In keeping with the requirements of this rule, Bell filed a depreciation study (the Study) in 1986. Before this filing, our last comprehensive review of Bell's depreciation rates was performed in 1983. In the years since the last review, there have been substantial changes in technology and competition, indicating a need for prescribing new rates where appropriate. The Study represents a comprehensive review of all classes of equipment.

BACKGROUND

In July of 1986, our Staff attended a meeting with Bell representatives held by Federal Communications Commission (FCC) officials as part of that agency's determination of appropriate depreciation factors for interstate purposes. Our intention in permitting our Staff to participate was to insure that the FCC received our views concerning Bell's depreciation reserve -- which we considered to be too low -- and the importance that we attached to company planning in establishing such depreciation factors. Unfortunately, the Study indicates confusion as to the intended role our Staff was to play in that meeting. It suggests that we reached an agreement with the company and the FCC regarding life factors **[*3]** to be applied equally for intra- and interstate depreciation purposes. Evidence of this erroneous conclusion by Bell is found in the Study's reliance on the lives agreed to by the company and the FCC at this meeting which, in many cases, contradict Bell's planning that would produce shorter lives. We do not recognize any agreement between Bell and the FCC governing specific life factors as binding on us for intrastate depreciation represcription purposes. Further, we disclaim any assertion that our Staff's participation in the FCC's meeting may have this unintended consequence.

By Order No. 17040, issued December 31, 1986, we accepted a Stipulation in Dockets Nos. 860674-TL, 860984-TL, 861139-TL and 861362-TL. Unless Bell requested a higher expense level, the Stipulation called for the implementation of new depreciation rates and recovery schedules to produce an increase of $73 Million in 1987 intrastate depreciation expense. The Stipulation also provided that Bell would design its depreciation rates and amortization schedules to produce at least $98 Million in increased depreciation expense in 1988.

By Order No. 17213, issued February 23, 1986, we permitted Bell to commence **[*4]** interim recording of the increased depreciation expense proposed in the Study. However, we conditioned this action upon Bell's later "trueing-up" its records to effectuate the depreciation rates and amortization schedules ultimately prescribed in this docket.

IMPLEMENTATION DATE FOR NEW RATES

Bell requested a January 1, 1987 implementation date for its newly-prescribed depreciation rates. All data and calculations submitted in the Study support this date. We believe this to be an appropriate effective date and will approve the requested implementation date.

RESERVE ADJUSTMENTS

As part of our review of the Study, we have examined the reserve position of each account. By Order No. 15798, issued March 10, 1986, we directed Bell to record an adjustment to the intrastate portion of depreciation reserve related to the interest synchronization of investment tax credits. As an interim step, this entry was to be recorded as a "bottom-line" reserve adjustment with a view toward its being applied to specific accounts when depreciation rates were represcribed. Additionally, the company was ordered to record monthly adjustments to the intrastate portion of the depreciation reserve **[*5]** in lieu of our reducing Bell's customer service rates. This initial adjustment and the subsequent monthly adjustments total $18,615,160 of intrastate depreciation expense and $29,002,443 on a total company basis.

Order No. 17040 directed Bell to make a one-time adjustment by booking $20,000,000 in 1986 intrastate depreciation expense in resolution of Docket No. 861139-TL, as part of $31,160,025 total company adjustment. Moreover, Bell was ordered to make an adjustment to intrastate depreciation reserve of $17,000,000 in 1988, which was part of a $26,094,591 total company reserve adjustment for that year.

We will adopt our Staff's recommendation that the above reserve adjustments, reflecting totals of $55,615,160 in intrastate and $86,257,059 in total company amounts, be applied to Account #232, the depreciation reserve for Inside Wire. This account is currently being amortized over a period of 10 years and is scheduled to be completed on September 30, 1991. These adjustments should be made by Bell without affecting the current amortization expense amount, thereby shortening the scheduled amortization period to be actually completed by May 1, 1989.

Finally, the Study proposes **[*6]** that the monthly depreciation reserve adjustments for interest synchronization of investment tax credits, established by Order No. 15798, be applied to the Inside Wire account. In our opinion, these adjustments should continue to be booked as "bottom-line" amounts in accordance with Order No. 15798. Therefore, we deny Bell's request and direct that the amounts, $43,753 in total company adjustments and $28,083 in intrastate adjustments, continue to be recorded monthly as a "bottom-line" reserve adjustment until the next depreciation represcription when these amounts will be allocated to specific accounts.

DEPRECIATION RATES

As a result of our comprehensive review of the Study, we will adopt our Staff's recommended depreciation rates, recovery schedules, amortization schedules and resultant expenses contained in the following attachments which are appended hereto:

Attachment 1 - Comparison of Depreciation Rates and Components;

Attachment 2 - Recovery Schedules;

Attachment 3 - Comparison of Depreciation Expenses

Attachment 4 - Amortization Schedules;

Attachment 5 - Comparison of Expenses 1987, 1988, 1989 Based on Staff Recommended Rates; and

Attachment 6 - Analysis of **[*7]** Reserve Position for Cable Accounts Being Impacted by Fiber Optics.

This action will result in an approximate increase in annual expenses of $112,672,000 on a total company basis when the rates are applied to investments as of January 1, 1987. The intrastate portion of this increase is about $75,975,000. Depreciation expenses for each specific account approved on an interim basis will be "trued-up" in accordance with Order No. 17213 to eliminate the incremental difference between the interim rates and those prescribed herein.

Attachment 1 provides a comparison of the Current, Company-Proposed and Staff-Recommended depreciation rates and components. Attachment 2 shows the Current, Company-Proposed and Staff-Recommended recovery schedule expenses and components. Attachment 3 shows the resultant estimated expenses, including those from recovery schedules authorized below and shown on Attachment 4. Attachment 5 demonstrates that the Staff-Recommended depreciations rates and amortization schedules can be implemented on January 1, 1987, in order to achieve the depreciation increases approved by Order No. 17040. Attachment 6 contains our Staff's calculation of a reserve deficit **[*8]** amounting to $156,584,000 that is caused by the effect on the remaining lives of outside cable plant by the increasing installation of fiber optics.

RECOVERY SCHEDULES

1. Central Office Equipment. Bell has identified investments in the Central Office Equipment accounts planned for retirement in the 1987-1989 period. We will adopt our Staff's recommendation that these investments be recovered over the remaining periods that the equipment will be serving the public, i.e., planned retirements for 1987 will be recovered during that year, those for 1988 will be recovered during 1987 and 1988, and those for 1989 will be recovered over the 1987-1989 period. Each schedule's monthly expense will be calculated by dividing net plant investment for that month by the number of months remaining in the amortization period.

2. Inside Wire. We will adopt our Staff's recommendation to accept Bell's proposal for applying to the Inside Wire account those reserve adjustments directed by Orders Nos. 15798 and 17040. The effect of these adjustments will be to shorten the remaining life of the recovery schedule for Inside Wire from 4 years and 3 months to 2 years and 5 months. **[*9]**

3. Reserve Deficits. As part of the 1983 depreciation review for Bell, two reserve deficits were calculated: (a) a historic reserve deficit which is being amortized over a five-year period to be completed June 30, 1988; and (b) a

prospective reserve deficit which is being amortized over a sixteen-year period that has 12.5 years remaining as of January 1, 1987. The Study requests that both deficits be combined and that a period of 3.5 years be established over which the aggregated amounts will be written off. We will accept Bell's proposal to reduce the write-off period for the prospective reserve deficit; however, we do not believe that the write-off period for the historic reserve deficit should be extended since this would keep in Bell's rate base an investment in plant which is no longer being used to serve the public. Accordingly, we adopt our Staff's recommendation that all amounts remaining on the historic deficit recovery schedule be charged off during 1987.

Additionally, the Study proposes that a new reserve imbalance calculation be performed by account for amortization over either a 3.5-year time period or shorter term. We reject this methodology because we believe **[*10]** that Bell's depreciation reserve balance, stated as a proportion of total investment, has been too low for some time. We do note some improvement over the last four years. At our 1983 depreciation represcription, we calculated a net reserve imbalance and adopted reserve-sensitive depreciation rates. We continue to believe that the use of straight remaining-life depreciation rates and recovery schedules from that point forward will correct future reserve imbalances without the need for recalculation at the time of each represcription.

On the other hand, the increasing installation of fiber optics appears to be affecting the three cable accounts: Aerial, Buried and Underground; with greater impact than was projected during the last represcription. For this reason, we recognize a current need for calculating a depreciation reserve imbalance for these accounts. Consequently, we will adopt a recovery schedule for these accounts in order to correct a net reserve deficit of $156,584,000. See Attachment 6.

With regard to the prospective deficit recovery schedule and the deficit calculated for the cable accounts discussed above, we will adopt our Staff's recommendation that these amounts **[*11]** be written-off ever a 3-year period. Attachment 2 shows the annual amortization expenses associated with these prospective reserve deficits. In order to achieve the increases in depreciation expense that were established in Order No. 17040 -- $75,975,000 for 1987 and $98,637,000 for 1988 -- the recovery schedules which we approve have been adjusted.

ANALYSIS OF ACCOUNTS

RESERVE POSITIONS:

As discussed above, we have rejected the Study's restatement of reserve imbalances for all accounts having remaining lives of 3.5 years or more with the exception of three cable accounts. The three cable accounts' reserves shall be restated to reflect its theoretically correct position.

BUILDINGS AND CENTRAL OFFICE EQUIPMENT:

1. Buildings. The Study proposes a composite depreciation rate for all subcategories in the Buildings account. We are concerned that modernization and miniaturization of switching equipment could lead to shorter lives for buildings housing such equipment than we earlier believed. It appears that Bell's conversion to digital and optical facilities may reduce the need for either maintaining the same or expanding building space. For this reason, **[*12]** we will approve separate depreciation rates for each Building subcategory.

2. Circuit-Other. We expect analog and digital circuit equipment to be retired as Bell converts its switching to all digital equipment. The Study proposes a composite depreciation rate for all digital and analog circuit subcategories. Also, the Study fails to separate optical carrier investment in this account from other carrier investments. In our opinion, an appropriate composite remaining life for these accounts would be nearer 7.5 years than the 8.6 years proposed by the Study. We will accept our Staff's recommendation that, for the retirement of circuit equipment during the period 1987-1989, the unrecovered investments be amortized over the period the equipment will remain in service. For the remaining investments in this account, we will adopt separate depreciation rates for each subcategory in order to state more accurately the appropriate recovery pattern for each group.

3. Circuit-DDS. We will approve the Study's proposal for lives and salvage values in this account which contains investments in central office electronic and auxiliary circuit equipment used in furnishing competitive **[*13]** Digital Data Systems Service.

4. Radio. The unrecovered investments in analog radio equipment that are planned for near-term retirement have been identified and placed on appropriate recovery schedules for amortization. For this account's remaining investments, we find that the life and salvage factors are consistent with the Study's planning; however, we will approve two separate subcategories: first, IMTS, Paging and Network Video Links equipment, and next, Miscellaneous Analog and Digital equipment.

5. Electronic Analog. The Study proposes that the unrecovered cost of electronic analog switchers planned for retirement during 1987 and 1988 be recovered over a 3-year period. Instead, we will accept our Staff's recommendation that this investment be recovered by the time these switchers are retired. For the remaining investment in this equipment, we reject the Study's proposal of an 8.6-year life because it is inconsistent with our method of determining remaining life. Bell supports its proposal as a reasonable compromise arrived at during the 1986 FCC meeting discussed above. While the agreement reached at this meeting may bind the company and the FCC, our Staff's **[*14]** role there, as previously explained, was not to enter into any agreement binding us. We cannot accept for purposes of an intrastate depreciation represcription any life factor reached as a compromise between Bell and the FCC. We will approve our Staff's recommendation of a remaining life in this account based on the company's economic planning. With respect to any additions to this account, we note that the factors that are appropriate for the embedded investment are inappropriate for new installations. For this reason, we will adopt our Staff's recommendation of an average life of 7 years and an estimated 14% net salvage for new additions. This life is based on the composite of the lives of each forecasted addition, and the salvage percentage is the anticipated salvage value for these additions as submitted by the company.

6. Electronic Digital. We will approve a recovery schedule addressing the unrecovered costs associated with two first-generation DMS-10 digital switchers planned for retirement in 1988. For the remaining investment in this account, we will adopt our Staff's recommendation that separate depreciation rates be applied to host switchers and remote switchers. **[*15]** For host switchers, the prescribed rates use a 20-year life span and a 1% interim retirement rate. Further, they assume that the life of remote switchers is tied to the host switcher without any interim retirements. We reject the Study's proposal that investment in these switching systems should not be subcategorized. For additions to existing host switchers in this account, we adopt a life of 14.1 years and a net salvage of 4%, resulting in a 6.8% depreciation rate. With respect to additions to existing remote switchers, we adopt a 17.2 year life and a 4% net salvage, which computes to a 5.6% depreciation rate. For new host switchers put into service during the period 1986-1988, we adopt a 5.2% depreciation rate, resulting from an 18.4-year life and a 4% net salvage. Any new remote switchers going into service during this period will assume a 4.8% depreciation rate, computed by using a 20-year life with a 4% net salvage value.

STATION EQUIPMENT:

1. Embedded CPE. Activity in this account has been insufficient to provide a basis for meaningful analysis. The Study proposes continuing the currently-prescribed depreciation rate of 12.1%. While the average service life **[*16]** factors which support this rate may still be appropriate, we believe that the average remaining life and the reserve position have changed since they were established. Consequently, we will adopt our Staff's recommendations that recognize a current view of life and salvage.

2. Embedded PBX. Similarly, the Study proposes retaining the currently-existing depreciation rates for this account because of a lack of sufficient data that would permit meaningful analysis. For the same reason given above, we will adopt our Staff's recommendation for updating the remaining life and reserve factors in this account to reflect current conditions.

3. Public Telephone. Following our approval of the individual ownership of pay telephones, 1,079 such instruments have been installed in the company's market area according to Bell. Further, the introduction of "smart" pay telephone equipment is rendering current public telephone equipment obsolete. Additionally, we are approving a

change from "cradle-to-grave" to "location" life in accounting procedures for this equipment. These three factors have been taken into consideration in our Staff's recommendations for shorter lives and higher **[*17]** salvage, which we will adopt for this account.

4. Private Line Equipment. This account was established as of January 1, 1986, and is composed of network channel terminating equipment located on customers' premises that was previously accounted for as Embedded CPE, Embedded PBX and Special PBX. The Study proposes a depreciation rate which represents a composite of the rates currently existing for each of these three accounts. Our Staff recommends using the projected life supported by current life factors and a salvage factor representing current composite net salvage, and we will adopt these recommendations.

5. TDD and Network Carrier Equipment. We will approve the Study's proposal to continue currently-prescribed life and salvage factors for these two accounts.

OUTSIDE PLANT:

1. Poles. While this account has been relatively stable, the Study assumes that the installation of optic fiber facilities will shortly begin to affect it. These new facilities will normally be placed in conduit or buried directly whereas the metallic facilities which they replace have been installed on poles. We believe that it is appropriate now to adopt the average remaining lives **[*18]** resulting from our application of existing underlying service life factors. The Study proposes a negative 66% net salvage value, based on recent experience; however, we note that this projection will be affected by certain changes flowing from the implementation of the FCC's revised Uniform System of Accounts which becomes effective in January of 1988. Certain indirect costs now being capitalized as costs of removal will then be expensed. For this reason, we recognize that current levels of removal costs may not be indicative of future amounts. Therefore, we will retain the existing salvage factor until our next depreciation represcription when the effect of this revision on this account can be ascertained.

2. Aerial and Buried Cable Drop. Drop wire was reclassified to Exchange Aerial and Buried Cable accounts at a time when these investments represented less than 10% of the associated primary cable investment and thus was not placed in separate subcategories. We believe it may not be practical for Bell to develop separate records in order to subcategorize drop wire investments in this account. For this reason, we will approve the same depreciation rates for drop wire **[*19]** investments as carried by their major associated cable accounts.

3. Fiber Cable - Exchange and Toll. We believe that early generations of fiber cable should have shorter lives than later generations because we expect refinements of early technology. This appears indicated by the replacement of multimode fiber with single-mode fiber which has increased the distances between repeaters for regenerating the optic signal, thus reducing the number of repeaters required. Also, we are aware of findings that this cable can be damaged by moisture that seeps through the sheathing to the fiber, an especially important consideration in Florida where high levels of humidity prevail. Moreover, we are aware of reports that fiber is susceptible to damage from high temperatures and vibrations. Our experience indicates that life estimates for new technologies tend to be overestimated. Based on these considerations, we will adopt a 20-year life and a zero salvage value for all fiber cable accounts. Moreover, based on our expectation that investment in fiber optics can be expected to grow significantly during the next three years, we will adopt a whole life rate. We believe this decision **[*20]** is appropriate because the relative young age of the investment will cause the average service life and the average remaining life to be approximately equal during this period.

4. Metallic Cable - Exchange and Toll. Increasing installation of fiber optic facilities is also expected to have an effect on the investment in these accounts. To date, fiber optics have been installed in trunk and feeder cable routes within the exchange and intraLATA toll areas. The cost of the new technology has decreased to the point that it is now more economical to install fiber for these high density and heavy usage routes than copper. A question remains as to when fiber will be installed as a replacement for copper in the existing distribution network. With the exception of broad-band data services, copper facilities are able to provide the same services as fiber facilities. On the other hand, with the conversion of feeder and trunk routes to fiber, the continued use of copper facilities in the distribution network may not be economical. The Study proposes lives for these accounts as agreed

to by the FCC and Bell at the meeting discussed above. They are neither supported by planning **[*21]** nor based on the Fisher-Pry Analysis that Bell performed and which it has advocated using. Our Staff calculated lives which are based on the company's planning that was submitted to address the replacement of copper feeder and trunk cables and assumes a continuation of the current lives for remaining cable investments. By comparison, the Study's proposed lives are longer than those computed by our Staff. Nevertheless, estimating the future effect that the installation of fiber will have on copper facilities is at this point so conjectural that we will accept our Staff's recommendation that we adopt the Study's proposals for these cable accounts.

5. <u>Submarine Cable - Metallic.</u> The Study does not subcategorize the fiber portion of submarine cable because it represented less than 10% of the total account's investment. We direct that a separate account and depreciation rate be established for this subcategory because we believe that fiber is a viable technology in which Bell will continue to invest. For the metallic portion of this account, we will approve our Staff's recommendations that are based on the existing underlying service life factor. We are forced to reject the **[*22]** Study's life proposals as merely representing a compromise between the FCC and Bell reached at the meeting discussed above.

6. <u>Aerial Wire.</u> We will approve the Study's life and salvage factors for this investment in bare, single and multiple insulated wire and associated items.

7. <u>Underground Conduit.</u> Since fiber can be installed in existing conduit irrespective of whether copper cable is installed there, the impact of future fiber installations on the life of conduit investments is currently uncertain. We will accept the Study's life proposals because we find them more in line with industry averages than the currently-prescribed life factors.

<u>GENERAL PLANT:</u>

1. <u>Furniture and Office Equipment.</u> Although our rules provide for subcategorization of this account into Office Furniture and Office Equipment or Machines accounts, the Study proposes a composite depreciation rate for the total account. We will approve separate depreciation rates for these two subaccounts. We will accept the Study's life and salvage factors for Office Furniture accounts as well as those for the Office Equipment accounts. We note that the acquisition of metallic, modular office furniture **[*23]** may shorten the life of existing office furniture. Further, we have observed that office machines such as typewriters, calculators and other non-software-controlled equipment are being replaced with word processing equipment and personal computers.

2. <u>Computers.</u> This account contains investments in both large mainframe computers and small mini- and microcomputers. As improved machines are developed and marketed at lower costs, existing machines are becoming obsolete. We will approve the Study's proposed life and salvage factors for this account.

3. <u>Other Communication Equipment.</u> Investments in this account consist of telephone and PBX equipment used by Bell in the conduct of its regulated business. We find the Study's proposed life and salvage factors acceptable; therefore, we will approve them for this account.

4. <u>Motor Vehicles.</u> The Study states that as of January 1, 1986, all additional vehicles are being leased. Bell proposes a depreciation rate for this account which represents a composite of life and salvage factors that have been developed for each category of light and heavy vehicles. We have determined that these factors are reasonable, and we will **[*24]** approve them; however, separate depreciation rates must be applied to each subcategory. Additionally, we direct that in the event any new vehicles are purchased, their investment should be maintained in separate subcategories in accordance with Rule 25-7.014(8). In this event, we further direct that the following rates be used in these accounts:

Vehicle	Life	Salvage	Rate
Passenger Cars	7 years	20%	11.4 %
Light Trucks	7 years	20%	11.4 %

Vehicle	Life	Salvage	Rate
Heavy Trucks	10 years	15%	8.5%
Special Purpose			
Vehicles	10 years	15%	8.5%

5. Tools and Other Work Equipment. We will approve the Study's proposed life and salvage values for this account which includes the investment in tools, garage equipment, shop machinery and miscellaneous work equipment with a cost of more than $200.

Now, therefore, in consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that depreciation reserve accounts of Southern Bell Telephone and Telegraph Company, its depreciation rates, its recovery schedules and its depreciation expenses are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the schedules appended **[*25]** to this Order.

By ORDER of the Florida Public Service Commission, this 24th day of AUGUST, 1987.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes (1985), to notify parties of any administrative hearing or judicial review of Commission orders that may be available, as well as the procedures and time limits that apply to such further proceedings. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule *25-22.029, Florida Administrative Code*. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, in the form provided by Rule 25-22.036(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and **[*26]** Reporting at his office at 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on September 14, 1987. In the absence of such a petition, this order shall become effective September 15, 1987, as provided by Rule 25-22.029(6), Florida Administrative Code, and as reflected in a subsequent order.

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

If this order becomes final and effective on September 15, 1987, any party adversely affected may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or by the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. **[*27]** The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT 1

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

CURRENT

ACCOUNT		AVERAGE REMAINING LIFE (yrs)	NET SALVAGE (%)	REMAINING LIFE RATE (%)
212	BUILDINGS			
	Multi-usage Bldgs.	38.0	4.0	2.2
	Single-usage Bldgs.	38.0	4.0	2.2
	Small Switching Bldgs.	38.0	4.0	2.2
	Work Centers, Office Bldgs.	38.0	4.0	2.2
221	CENTRAL OFFICE EQUIPMENT			
	Circuit-Analog	11.1	3.0	6.6
	Circuit-Digital	11.1	3.0	6.6
	Circuit-Fiber	11.1	3.0	6.6
	Circuit-DDS	11.1	2.0	7.9
	Radio			
	IMTS, Paging, TV Links Res.	8.9	(13.0)	7.2
	Digital, Misc. Analog Res.	8.9	(13.0)	7.2
	ESS-Analog	16.3	4.0	4.8
	ESS-Digital			
	Host	17.5	0.0	5.7
	Remote	17.5	0.0	5.7
231	STATION APPARATUS (Embedded)			12.1
234	LARGE PBX (Embedded)			13.8
235	PUBLIC TELEPHONE	7.8	1.0	10.2
236	PRIVATE LINE			13.5
237	TDD	5.0	1.0	16.1
238	NETWORK CARRIER (CPE)	4.5	2.0	14.5
241	POLES	25.0	(45.0)	4.8
242.1	AERIAL CABLE			
	Exch. Metallic	17.2	(26.0)	5.9
	Exch. Optical	17.2	(26.0)	5.9
	Toll Metallic	9.0	19.0	4.3
	Toll Optical	9.0	19.0	4.3
242.2	UNDERGROUND CABLE			
	Exch. Metallic	27.0	(5.0)	3.3
	Exch. Optical	27.0	(5.0)	3.3
	Toll Metallic	12.9	11.0	4.1
	Toll Optical	12.9	11.0	4.1
242.3	BURIED CABLE			

	Exch. Metallic	21.0	(5.0)	4.2
	Exch. Optical	21.0	(5.0)	4.2
	Toll Metallic	13.6	(3.0)	4.4
	Toll Optical	13.6	(3.0)	4.4
242.4	SUBMARINE CABLE			
	Metallic	16.7	(2.0)	4.1
	Optical	16.7	(2.0)	4.1
234	AERIAL WIRE	3.3	(24.0)	25.0
244	CONDUIT	58.0	(5.0)	1.6
261	FURN. & OFF. EQUIP.			
	Office Furn.	14.4	2.0	5.6
	Office Mach.	14.4	2.0	5.6
	Computers	4.1	0.0	14.7
262	OTHER COMM. EQUIP.			12.4
264	VEHICLES			
	Light Vehicles	4.5	21.0	9.9
	Heavy Trucks	4.5	21.0	9.9
	Other Work Equip.	12.8	2.0	6.5

[*28]

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		COMPANY PROPOSED			
		AVERAGE			REMAINING
		REMAINING	NET		LIFE
ACCOUNT		LIFE	SALVAGE	RESERVE *	RATE
		(yrs)	(%)	(%)	(%)
212	BUILDINGS				
	Multi-usage Bldgs.	38.0	4.0	12.2	2.2
	Single-usage Bldgs.	38.0	4.0	12.2	2.2
	Small Switching Bldgs.	38.0	4.0	12.2	2.2
	Work Centers, Office Bldgs.	38.0	4.0	12.2	2.2
221	CENTRAL OFFICE EQUIPMENT				
	Circuit-Analog	8.6	3.0	29.9	7.8
	Circuit-Digital	8.6	3.0	29.9	7.8

* Denotes Company calculated restated reserve.

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		COMPANY PROPOSED			
		AVERAGE			REMAINING
		REMAINING	NET		LIFE
ACCOUNT		LIFE	SALVAGE	RESERVE *	RATE
	Circuit-Fiber	8.6	3.0	29.9	7.8
	Circuit-DDS	5.6	2.0	34.8	11.3
	Radio				
	IMTS, Paging, TV Links Res.	2.4	(13.0)	66.4	19.4
	Digital, Misc. Analog Res.	2.4	(13.0)	66.4	19.4
	ESS-Analog	8.6	4.0	33.8	7.2
	ESS-Digital				
	Host	18.7	0.0	6.5	5.0
	Remote	18.7	0.0	6.5	5.0
231	STATION APPARATUS (Embedded)				12.1
234	LARGE PBX (Embedded)				13.8
235	PUBLIC TELEPHONE	3.2	20.0	29.9	15.7
236	PRIVATE LINE				13.5
237	TDD	5.0	1.0	20.4	15.7
238	NETWORK CARRIER (CPE)	4.5	2.0	32.6	14.5
241	POLES	29.0	(66.0)	25.4	4.8
242.1	AERIAL CABLE				
	Exch. Metallic	17.0	(22.0)	24.9	5.7
	Exch. Optical	24.0	(29.0)	9.9	5.0
	Toll Metallic	6.5	43.0	7.8	7.6
	Toll Optical	24.0	(8.0)	4.3	4.3
242.2	UNDERGROUND CABLE				
	Exch. Metallic	18.8	0.0	27.7	3.8
	Exch. Optical	24.0	(24.0)	5.0	5.0
	Toll Metallic	7.1	22.0	36.9	5.8
	Toll Optical	23.0	(9.0)	8.7	4.4
242.3	BURIED CABLE				
	Exch. Metallic	16.7	(10.0)	26.5	5.0
	Exch. Optical	24.0	(12.0)	7.4	4.4
	Toll Metallic	7.2	(5.0)	63.1	5.8

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		COMPANY PROPOSED			
		AVERAGE			REMAINING
		REMAINING	NET		LIFE
ACCOUNT		**LIFE**	**SALVAGE**	**RESERVE** *	**RATE**
	Toll Optical	23.0	(5.0)	8.4	4.2
242.4	SUBMARINE CABLE				
	Metallic	15.0	(2.0)	38.3	4.2
	Optical	15.0	(2.0)	38.3	4.2
234	AERIAL WIRE	2.4	(20.0)	103.8	6.8
244	CONDUIT	46.0	(5.0)	17.2	1.9
261	FURN. & OFF. EQUIP.				
	Office Furn.	9.8	2.0	26.5	7.3
	Office Mach.	9.8	2.0	26.5	7.3
	Computers	3.5	0.0	51.9	13.7
262	OTHER COMM. EQUIP.	5.3	30.0	34.4	6.7
264	VEHICLES				
	Light Vehicles	2.6	21.0	50.4	11.0
	Heavy Trucks	2.6	21.0	50.4	11.0
	Other Work Equip.	11.8	2.0	22.2	6.4

[*29]

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		STAFF RECOMMENDED			
		AVERAGE			REMAINING
		REMAINING	NET	BOOK	LIFE
ACCOUNT		**LIFE**	**SALVAGE**	**RESERVE**	**RATE**
		(yrs)	(%)	(%)	(%)
212	BUILDINGS				

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		STAFF RECOMMENDED			
		AVERAGE			REMAINING
		REMAINING	NET	BOOK	LIFE
ACCOUNT		**LIFE**	**SALVAGE**	**RESERVE**	**RATE**
	Multi-usage Bldgs.	49.0	3.0	12.53	1.7
	Single-usage Bldgs.	45.0	3.0	17.09	1.8
	Small Switching Bldgs.	21.0	6.0	23.21	3.4
	Work Centers, Office Bldgs.	27.0	6.0	11.15	3.1
221	CENTRAL OFFICE EQUIPMENT				
	Circuit-Analog	11.7	3.0	15.74	6.9
	Circuit-Digital	9.7	3.0	14.89	8.5
	Circuit-Fiber	10.0	0.0	10.22	+ 10.0
	Circuit-DDS	5.6	2.0	17.79	14.3
	Radio				
	IMTS, Paging, TV Links Res.	3.5	0.0	43.02	16.3
	Digital, Misc. Analog Res.	10.0	(3.0)	82.11	2.1
	ESS-Analog	7.9	(4.0)	17.73	10.9
	ESS-Digital				
	Host	15.1	(4.0)	7.22	6.4
	Remote	18.2	(4.0)	5.56	5.4
231	STATION APPARATUS (Embedded)	5.9	5.0	42.37	8.9
234	LARGE PBX (Embedded)	5.8	9.0	9.18	14.1
235	PUBLIC TELEPHONE	4.0	20.0	30.21	12.4
236	PRIVATE LINE	6.2	9.0	35.77	8.9
237	TDD	5.0	1.0	12.00	17.4
238	NETWORK CARRIER (CPE)	4.5	2.0	25.77	16.1
241	POLES	26.0	(45.0)	26.95	4.5
242.1	AERIAL CABLE				
	Exch. Metallic	17.0	(22.0)	** 25.10	5.7
	Exch. Optical	20.0	0.0	21.55	+ 5.0
	Toll Metallic	6.5	43.0	** 7.60	7.6
	Toll Optical	20.0	0.0	4.85	+ 5.0

** Denotes Staff calculated restated reserve.

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Rates and Components

		STAFF RECOMMENDED			
		AVERAGE			REMAINING
		REMAINING	NET	BOOK	LIFE
ACCOUNT		LIFE	SALVAGE	RESERVE	RATE
242.2	UNDERGROUND CABLE				
	Exch. Metallic	18.8	0.0	** 28.56	3.8
	Exch. Optical	20.0	0.0	15.63	+ 5.0
	Toll Metallic	7.1	22.0	** 36.82	5.8
	Toll Optical	20.0	0.0	28.00	+ 5.0
242.3	BURIED CABLE				
	Exch. Metallic	16.7	(10.0)	** 26.50	5.0
	Exch. Optical	20.0	0.0	12.73	+ 5.0
	Toll Metallic	7.2	(5.0)	** 63.24	5.8
	Toll Optical	20.0	0.0	35.93	+ 5.0
242.4	SUBMARINE CABLE				
	Metallic	16.4	(2.0)	38.12	3.9
	Optical	20.0	0.0	5.05	+ 5.0
234	AERIAL WIRE	2.4	(20.0)	109.11	4.5
244	CONDUIT	46.0	(5.0)	15.11	2.0
261	FURN. & OFF. EQUIP.				
	Office Furn.	11.5	2.0	11.90	7.5
	Office Mach.	6.5	2.0	20.38	11.9
	Computers	3.5	0.0	49.97	14.3
262	OTHER COMM. EQUIP.	5.3	30.0	26.35	8.2
264	VEHICLES				
	Light Vehicles	2.1	23.0	52.28	11.8
	Heavy Trucks	3.9	18.0	43.79	9.8
	Other Work Equip.	11.8	2.0	21.80	6.5

[*30]

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ATTACHMENT 2

[+] + Denotes whole life rates.

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Recovery Schedules

	CURRENT		
	AVERAGE REMAINING LIFE (yrs)	**NET SALVAGE** (%)	**REMAINING LIFE RATE** (%)
RECOVERY SCHEDULES			
Electromechanical (1983-1985 Rets.)	3 YEAR AMORTIZATION		
Electromechanical (1987-1988 Rets.)			10.8
Carrier (1987-1989 Rets.)	11.1	3.0	6.6
Radio (1987-1988 Rets.)	8.9	(13.0)	7.2
ESS Analog (1983-1985 Rets.)	3 YEAR AMORTIZATION		
ESS Analog (1987-1989 Rets.)	16.3	4.0	4.8
Electronic Digital (1988 Rets.)	17.5	0.0	5.7
Inside Wire	10 YEAR AMORTIZATION		
RESERVE DEFICIT			
Historic	5 YEAR AMORTIZATION		
Prospective	16 YEAR AMORTIZATION		
Company Recalculated			
Outside Plant (Cable)			

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Recovery Schedules

	COMPANY PROPOSED	
	AVERAGE	**REMAINING**

	REMAINING LIFE (yrs)	NET SALVAGE (%)	RESERVE (%)	LIFE RATE (%)
RECOVERY SCHEDULES				
Electromechanical (1983-1985 Rets.)				
Electromechanical (1987-1988 Rets.)	2 YEAR AMORTIZATION			
Carrier (1987-1989 Rets.)	8.6	3.0	29.9	7.8
Radio (1987-1988 Rets.)	2.4	(13.0)	66.4	19.8
ESS Analog (1983-1985 Rets.)				
ESS Analog (1987-1989 Rets.)	3 YEAR AMORTIZATION			
Electronic Digital (1988 Rets.)	18.7	0.0	6.5	5.0
Inside Wire	2.4 YEAR AMORTIZATION			
RESERVE DEFICIT				
Historic	3.5 YEAR AMORTIZATION			
Prospective	3.5 YEAR AMORTIZATION			
Company Recalculated	3.5 YEAR AMORTIZATION			
Outside Plant (Cable)				

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SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Recovery Schedules

	STAFF RECOMMENDED			
	AVERAGE REMAINING LIFE	NET SALVAGE	BOOK RESERVE	REMAINING LIFE RATE
RECOVERY SCHEDULES	(yrs)	(%)	(%)	(%)
Electromechanical (1983-1985 Rets.)				

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Recovery Schedules

	STAFF RECOMMENDED			
	AVERAGE			**REMAINING**
	REMAINING	**NET**	**BOOK**	**LIFE**
	LIFE	**SALVAGE**	**RESERVE**	**RATE**
Electromechanical (1987-1988 Rets.)	3 YEAR AMORTIZATION			
Carrier (1987-1989 Rets.)	3 YEAR AMORTIZATION			
Radio (1987-1988 Rets.)	3 YEAR AMORTIZATION			
ESS Analog (1983-1985 Rets.)				
ESS Analog (1987-1989 Rets.)	3 YEAR AMORTIZATION			
Electronic Digital (1988 Rets.)	2 YEAR AMORTIZATION			
Inside Wire	2.4 YEAR AMORTIZATION			
RESERVE DEFICIT				
Historic	1 YEAR AMORTIZATION			
Prospective	3 YEAR AMORTIZATION			
Company Recalculated				
Outside Plant (Cable)	3 YEAR AMORTIZATION			

		CURRENT		COMPANY PROPOSED		
	(1-1-87)	**REMAINING**		**REMAINING**		**CHANGE IN**
	INVESTMENT	**LIFE**	**EXPENSES**	**LIFE**	**EXPENSES**	**EXPENSES**
	(000)	**RATE**	**(000)**	**RATE**	**(000)**	**(000)**
	($)	(%)	($)	(%)	($)	($)
RECOVERY SCHEDULES						
Electromechanical						

	CURRENT			COMPANY PROPOSED		
	(1-1-87)	REMAINING		REMAINING		CHANGE IN
	INVESTMENT	LIFE	EXPENSES	LIFE	EXPENSES	EXPENSES
	(000)	RATE	(000)	RATE	(000)	(000)
(1983-1985 Rets.)		3 YR.	25,062		0	(25,062)
Electromechanical						
(1987-1988 Rets.)	96,216	10.0	10,391	2 YR.	13,512	3,121
Carrier						
(1987-1989 Rets.)	110,389	6.6	7,286	7.8	8,610	1,324
Radio						
(1987-1988 Rets.)	5,177	7.2	373	19.4	1,004	631
ESS Analog						
(1983-1985 Rets.)		3 YR.	8,126		0	(8,126)
ESS Analog						
(1987-1989 Rets.)	88,359	4.8	4,241	3 YR.	17,033	12,792
Electronic Digital						
(1988 Rets.)	2,455	5.7	140	5.0	123	(17)
Inside Wire	418,270	10 YR.	36,208	2.4 YR.	36,733	525
RESERVE DEFICIT						
Historic	(37,932)	5 YR.	24,591	2.4 YR.	10,838	(13,753)
Prospective	(111,681)	16 YR.	8,911	3.5 YR.	31,909	22,998
Company Recalculated	(390,911)		0	3.5 YR.	111,690	111,690
Outside Plant						
(Cable)	(156,584)		0			0
TOTAL	720,866		125,329		231,452	106,123

[*32]

STAFF RECOMMENDED		
REMAINING		CHANGE IN
LIFE	EXPENSES	EXPENSES

	RATE	(000)	(000)
	(%)	($)	($)
RECOVERY SCHEDULES			
Electromechanical			
(1983-1985 Rets.)		0	(25,062)
Electromechanical			
(1987-1988 Rets.)	3 YR.	15,197	4,806
Carrier			
(1987-1989 Rets.)	3 YR.	32,077	24,791
Radio			
(1987-1988 Rets.)	3 YR.	1,133	760
ESS Analog			
(1983-1985 Rets.)		0	(8,126)
ESS Analog			
(1987-1989 Rets.)	3 YR.	27,484	23,243
Electronic Digital			
(1988 Rets.)	2 YR.	722	582
Inside Wire	2.4 YR.	36,208	0
RESERVE DEFICIT			
Historic	1 YR.	37,932	13,341
Prospective	3 YR.	8,911	0
Company Recalculated		0	0
Outside Plant			
(Cable)	3 YR.	13,220	13,220
TOTAL		172,884	47,555

ATTACHMENT 3

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Expenses

		CURRENT
	(1-1-87)	**REMAININ G**

ACCOUNT		INVESTMEN T	LIFE	EXPENSE S
		(000)	RATE	(000)
		($)	(%)	($)
212	BUILDINGS			
	Multi-usage Bldgs.	$242,706	2.2	$5,340
	Single-usage Bldgs.	157,385	2.2	3,462
	Small Switching Bldgs.	30,083	2.2	662
	Work Centers, Office Bldgs.	128,775	2.2	2,833
221	CENTRAL OFFICE EQUIPMENT			
	Circuit-Analog	320,493	6.6	21,153
	Circuit-Digital	487,628	6.6	32,183
	Circuit-Fiber	47,439	6.6	3,131
	Circuit-DDS	18,662	7.9	1,474
	Radio			
	IMTS, Paging, TV Links Rea.	6,386	7.2	460
	Digital, Misc. Analog Rea.	4,941	7.2	356
	ESS-Analog	612,427	4.8	29,396
	ESS-Digital			
	Host	246,154	5.7	14,031
	Remote	15,438	5.7	880
231	STATION APPARATUS (Eabedded)	262	12.1	32
234	LARGE PBX (Eabedded)	828	13.8	114
235	PUBLIC TELEPHONE	63,063	10.2	6,432
236	PRIVATE LINE	52,667	13.5	7,110
237	TDD	25	16.1	4
238	NETWORK CARRIER (CPE)	8,576	14.5	1,244
241	POLES	90,132	4.8	4,326
242.1	AERIAL CABLE			
	Exch. Metallic	501,256	5.9	29,574
	Exch. Optical	2,000	5.9	118
	Toll Metallic	1,000	4.3	43
	Toll Optical	1,463	4.3	63
242.2	UNDERGROUND CABLE			
	Exch. Metallic	667,959	3.3	22,043
	Exch. Optical	59,380	3.3	1,960
	Toll Metallic	16,912	4.1	693
	Toll Optical	8,338	4.1	342
242.3	BURIED CABLE			
	Exch. Metallic	1,492,480	4.2	62,684
	Exch. Optical	13,650	4.2	573
	Toll Metallic	13,597	4.4	598

	Toll Optical	3,418	4.4	150
242.4	SUBMARINE CABLE			
	Metallic	10,390	4.1	426
	Optical	574	4.1	24
234	AERIAL WIRE	4,586	25.0	1,147
244	COHDUIT	515,614	1.6	8,250
261	FURN. & OFF. EQUIP.			
	Office Furn.	20,929	5.6	1,172
	Office Mach.	7,812	5.6	437
	Computers	154,030	14.7	22,642
262	OTHER COMM. EQUIP.	93,399	12.4	11,581
264	VEHICLES			
	Light Vehicles	41,087	9.9	4,068
	Heavy Trucks	20,700	9.9	2,049
	Other Work Equip.	66,155	6.5	4,300
	Total	6,250,799		309,560
	Recovery Schedule Totals	720,866		125,329
	TOTAL	6,971,665		434,889

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SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Expenses

		COMPANY PROPOSED		
		REMAINING		**CHANGE IN**
ACCOUNT		**LIFE**	**EXPENSES**	**EXPENSES**
		RATE	**(000)**	**(000)**
		(%)	($)	($)
212	BUILDINGS			
	Multi-usage Bldgs.	2.2	$5,340	$0
	Single-usage Bldgs.	2.2	3,462	0
	Small Switching Bldgs.	2.2	662	0
	Work Centers, Office Bldgs.	2.2	2,833	0
221	CENTRAL OFFICE EQUIPMENT			
	Circuit-Analog	7.8	24,998	3,845
	Circuit-Digital	7.8	38,035	5,852

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Expenses

		COMPANY PROPOSED		
		REMAINING		CHANGE IN
ACCOUNT		LIFE	EXPENSES	EXPENSES
		RATE	(000)	(000)
	Circuit-Fiber	7.8	3,700	569
	Circuit-DDS	11.3	2,109	635
	Radio			
	IMTS, Paging, TV Links Rea.	19.4	1,239	779
	Digital, Misc. Analog Rea.	19.4	959	603
	ESS-Analog	7.2	44,095	14,699
	ESS-Digital			
	Host	5.0	12,308	(1,723)
	Remote	5.0	772	(108)
231	STATION APPARATUS (Eabedded)	12.1	32	0
234	LARGE PBX (Eabedded)	13.8	114	0
235	PUBLIC TELEPHONE	15.7	9,901	3,469
236	PRIVATE LINE	13.5	7,110	0
237	TDD	15.7	4	0
238	NETWORK CARRIER (CPE)	14.5	1,244	0
241	POLES	4.8	4,326	0
242.1	AERIAL CABLE			
	Exch. Metallic	5.7	28,572	(1,002)
	Exch. Optical	5.0	100	(18)
	Toll Metallic	7.6	76	33
	Toll Optical	4.3	63	0
242.2	UNDERGROUND CABLE			
	Exch. Metallic	3.8	25,382	3,339
	Exch. Optical	5.0	2,969	1,009
	Toll Metallic	5.8	981	288
	Toll Optical	4.4	367	25
242.3	BURIED CABLE			
	Exch. Metallic	5.0	74,624	11,940
	Exch. Optical	4.4	601	28
	Toll Metallic	5.8	789	191
	Toll Optical	4.2	144	(6)
242.4	SUBMARINE CABLE			

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Expenses

		COMPANY PROPOSED		
		REMAINING		**CHANGE IN**
ACCOUNT		**LIFE**	**EXPENSES**	**EXPENSES**
		RATE	**(000)**	**(000)**
	Metallic	4.2	436	10
	Optical	4.2	24	0
234	AERIAL WIRE	6.8	312	(835)
244	CONDUIT	1.9	9,797	1,547
261	FURN. & OFF. EQUIP.			
	Office Furn.	7.3	1,528	356
	Office Mach.	7.3	570	133
	Computers	13.7	21,102	(1,540)
262	OTHER COMM. EQUIP.	6.7	6,258	(5,323)
264	VEHICLES			
	Light Vehicles	11.0	4,520	452
	Heavy Trucks	11.0	2,277	228
	Other Work Equip.	6.4	4,234	(66)
	Total		348,969	39,409
	Recovery Schedule Totals		* 231,452	* 106,123
	TOTAL		580,421	145,532

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SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Comparison of Depreciation Expenses

		STAFF RECOMMENDED		
		REMAINING		**CHANGE IN**

* + Denotes whole life rates.

Includes full year amortization of reserve deficit expenses. The company has proposed that amortization begin April 1987, resulting in total company expenses for 1987 of $112.7 million (75.975 million Intrastate) .

ACCOUNT		LIFE RATE (%)	EXPENSES (000) ($)	EXPENSES (000) ($)
212	BUILDINGS			
	Multi-usage Bldgs.	1.7	$4,126	($1,214)
	Single-usage Bldgs.	1.8	2,833	(629)
	Small Switching Bldgs.	3.4	1,023	361
	Work Centers, Office Bldgs.	3.1	3,992	1,159
221	CENTRAL OFFICE EQUIPMENT			
	Circuit-Analog	6.9	22,114	961
	Circuit-Digital	8.5	41,448	9,265
	Circuit-Fiber	10.0	4,744	1,613
	Circuit-DDS	14.3	2,669	1,195
	Radio			
	IMTS, Paging, TV Links Rea.	16.3	1,041	581
	Digital, Misc. Analog Rea.	2.1	104	(252)
	ESS-Analog	10.9	66,755	37,359
	ESS-Digital			
	Host	6.4	15,754	1,723
	Remote	5.4	834	(46)
231	STATION APPARATUS (Eabedded)	8.9	23	(9)
234	LARGE PBX (Eabedded)	14.1	117	3
235	PUBLIC TELEPHONE	12.4	7,820	1,388
236	PRIVATE LINE	8.9	4,687	(2,423)
237	TDD	17.4	4	0
238	NETWORK CARRIER (CPE)	16.1	1,381	137
241	POLES	4.5	4,056	(270)
242.1	AERIAL CABLE			
	Exch. Metallic	5.7	28,572	(1,002)
	Exch. Optical	+ 5.0	100	(18)
	Toll Metallic	7.6	76	33
	Toll Optical	+ 5.0	73	10
242.2	UNDERGROUND CABLE			
	Exch. Metallic	3.8	25,382	3,339
	Exch. Optical	+ 5.0	2,969	1,009
	Toll Metallic	5.8	981	288
	Toll Optical	+ 5.0	417	75
242.3	BURIED CABLE			
	Exch. Metallic	5.0	74,624	11,940
	Exch. Optical	+ 5.0	683	110
	Toll Metallic	5.8	789	191

	Toll Optical	+ 5.0	171	21
242.4	SUBMARINE CABLE			
	Metallic	3.9	405	(21)
	Optical	+ 5.0	29	5
234	AERIAL WIRE	4.5	206	(941)
244	COHDUIT	2.0	10,112	2,062
261	FURN. & OFF. EQUIP.			
	Office Furn.	7.5	1,570	398
	Office Mach.	11.9	930	493
	Computers	14.3	22,026	(616)
262	OTHER COMM. EQUIP.	8.2	7,659	(3,922)
264	VEHICLES			
	Light Vehicles	11.8	4,848	780
	Heavy Trucks	9.8	2,029	(20)
	Other Work Equip.	6.5	4,300	0
	Total		374,676	65,116
	Recovery Schedule Totals		172,884	47,555
	TOTAL		547,560	112,671

[*35]

ATTACHMENT 4

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Amortization Schedules

ACCOUNT	REMAINING INVESTMENT	RELATED RESERVE	EXPECTED SALVAGE	NET PLANT TO BE RECOVERED
	($)	($)	($)	($)
	(a)	(b)	(c)	(d)
AMORTIZATION SCHEDULES				
Electromechanical				
(1987 Rets.)	** 60,182,612	50,686,322	(2,263,500)	11,759,790
(1988 Rets.)	** 36,033,266	*** 30,226,440	(1,068,242)	6,875,068

** Includes short-lived additions.

*** Includes residual reserve from manual switching of $469,308.

Melinda Marzicola **ATTACHMENT B**

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Amortization Schedules

ACCOUNT	REMAINING INVESTMENT ($)	RELATED RESERVE ($)	EXPECTED SALVAGE ($)	NET PLANT TO BE RECOVERED ($)
Carrier-Other				
(1987 Rets.)	31,470,194	16,340,283	406,400	14,723,511
(1988 Rets.)	36,487,923	17,361,094	407,912	18,718,917
(1989 Rets.)	42,430,883	17,891,201	557,704	23,981,978
Radio				
(1987 Rets.)	3,310,862	2,483,740	(51,250)	878,372
(1988 Rets.)	1,866,438	1,459,432	(102,500)	509,506
ESS Analog				
(1987 Rets.)	10,075,650	2,006,820	403,026	7,665,804
(1988 Rets.)	** 14,259,053	2,456,969	775,203	11,026,881
(1989 Rets.)	** 64,024,439	* 13,501,124	3,288,778	47,234,537
Electronic Digital	2,454,896	230,387	780,000	1,444,509
Inside Wire	418,270,412	**** 332,486,999	0	85,783,413
Reserve Deficit				
(Established 1983)				
Historic	0	(37,931,693)	0	37,931,693
Prospective	0	(111,681,299)	0	111,681,299
Outside Plant				
Cable Deficit	0	(156,584,000)	0	156,584,000
TOTAL	720,866,628	180,933,819	3,133,531	536,799,278

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* Includes residual reserve of $5,593,755 from recovery schedule established in 1983.

**** Includes reserve adjustments for Interest Synchronization for 1986 and 1987, 1986 and 1988 one-time depreciation adjustments per stipulation in Docket nos. 860674-TL, 860984-TP, 861139-TL and 861362-TL.

Melinda Marzicola **ATTACHMENT B**

SOUTHERN BELL TELEPHONE & TELEGRAPH

TOTAL COMPANY 1986 STUDY

Amortization Schedules

ACCOUNT	**NO. of YRS.**	**EXPENSES 1987**	**1988**	**1989**
AMORTIZATION SCHEDULES				
Electromechanical				
(1987 Rets.)	1	11,759,790		
(1988 Rets.)	2	3,437,534	3,437,534	
Carrier-Other				
(1987 Rets.)	1	14,723,511		
(1988 Rets.)	2	9,359,459	9,359,459	
(1989 Rets.)	3	7,993,993	7,993,993	7,993,993
Radio				
(1987 Rets.)	1	878,372		
(1988 Rets.)	2	254,753	254,753	
ESS Analog				
(1987 Rets.)	1	7,665,804		
(1988 Rets.)	2	5,513,441	5,513,441	
(1989 Rets.)	3	14,305,079	16,464,729	16,464,729
Electronic Digital	2	722,255	722,255	
Inside Wire	2.4	36,208,224	36,208,224	13,366,965
Reserve Deficit				
(Established 1983)				
Historic	1	37,931,693		
Prospective	3	8,911,000	51,385,000	51,385,000
Outside Plant				
Cable Deficit	3	13,220,000	75,155,000	68,209,000
TOTAL		172,884,908	206,494,388	157,419,687

[*37]

ATTACHMENT 5

SOUTHERN BELL TELEPHONE & TELEGRAPH

COMPARISON OF EXPENSES

1987, 1988, 1989 BASED ON STAFF

RECOMMENDED RATES

	CURRENT EXPENSES	1987 EXPENSES		
			TOTAL	
			COMPANY	INTRASTATE
	TOTAL-COMPANY	TOTAL-COMPANY	INCREASE	INCREASE
Depreciation Rates	$309,560	$374,676	$65,116	$43,908
Recovery Schedules	91,827	112,822	20,995	14,157
Historic Deficit	24,591	37,932	13,341	8,996
Prospective Deficit	8,911	8,911		
O.S.P. Cable Deficit		13,220	13,220	8,914
Total	$434,889	$547,561	$112,672	$75,975

SOUTHERN BELL TELEPHONE & TELEGRAPH

COMPARISON OF EXPENSES

1987, 1988, 1989 BASED ON STAFF

RECOMMENDED RATES

	1988 EXPENSES		
		TOTAL	
		COMPANY	INTRASTATE
	TOTAL-COMPANY	INCREASE	INCREASE
Depreciation Rates	$374,676	$65,116	$43,908
Recovery Schedules	79,954	(11,873)	(8,006)
Historic Deficit		(24,591)	(16,582)
Prospective Deficit	51,385	42,474	28,640

SOUTHERN BELL TELEPHONE & TELEGRAPH

COMPARISON OF EXPENSES

1987, 1988, 1989 BASED ON STAFF

RECOMMENDED RATES

1988 EXPENSES

	TOTAL-COMPANY	TOTAL COMPANY INCREASE	INTRASTATE INCREASE
O.S.P. Cable Deficit	75,155	75,155	50,677
Total	$581,170	$146,281	$98,637

SOUTHERN BELL TELEPHONE & TELEGRAPH

COMPARISON OF EXPENSES

1987, 1988, 1989 BASED ON STAFF

RECOMMENDED RATES

1989 EXPENSES

	TOTAL-COMPANY	TOTAL COMPANY INCREASE	INTRASTATE INCREASE
Depreciation Rates	$374,676	$65,116	$43,908
Recovery Schedules	37,826	(54,001)	(36,413)
Historic Deficit		(24,591)	(16,582)
Prospective Deficit	51,385	42,474	28,640
O.S.P. Cable Deficit	68,209	68,209	45,993
Total	$532,096	$97,207	$65,546

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ATTACHMENT 6

SOUTHERN BELL TELEPHONE AND TELEGRAPH

1987 STUDY

ANALYSIS OF RESERVE POSITION FOR CABLE

ACCOUNTS BEING IMPACTED BY FIBER OPTICS

	(1-1-87) Investment ($ 000)	(1-1-87) Book Reserve ($ 000)	Theoretical Reserve Based on Staff Recommended Rates ($ 000)
Aerial Cable			
Exch. Metallic	$ 501,256	$133,115	$125,815
Toll Metallic	1,000	23	76
Underground Cable			
Exch. Metallic	667,959	145,872	190,769
Toll Metallic	16,912	6,155	6,227
Buried Cable			
Exch. Metallic	1,492,580	278,236	395,507
Toll Metallic	13,597	7,008	8,599
Total	$2,693,204	$570,409	$726,993

Book reserve	= $ 570,409
Less: Theoretical reserve based on Staff recommended rates	= 726,993
Reserve Deficit	$ (156,584)

1988 Fla. PUC LEXIS 202

Florida Public Service Commission

January 4, 1988

DOCKET NO. 870964-TL; ORDER NO. 18642, 88-1 FPSC 151

FL Public Service Commission Decisions

Reporter
1988 Fla. PUC LEXIS 202 *

In re: GULF TELEPHONE COMPANY - 1987 Depreciation Study

Core Terms

depreciate, retire, gulf, amortize, cable, telephone company, notice, microwave, carrier, surplus, switch, plant

Panel: ; The following Commissioners participated in the disposition of this matter: KATIE NICHOLS, Chairman; THOMAS M. BEARD; GERALD L. GUNTER; JOHN T. HERNDON; MICHAEL McK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING NEW DEPRECIATION RATES, RECOVERY SCHEDULES AND ADJUSTMENT OF DEPRECIATION RESERVE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission of its intent to approve the request of Gulf Telephone Company (Gulf) for new depreciation rates, recovery schedules and adjustment of depreciation reserves pursuant to Sections 350.127 and 364.03, Florida Statutes (1985), and Rule 25-4.0175, Florida Administrative Code. This action is preliminary in nature and will become final unless a person whose interests are adversely affected files a petition for formal proceeding pursuant to Rule 25-22.029.

Rule 25-4.0175(7) requires telephone companies to periodically file a comprehensive depreciation study at least once every three years. In keeping with the requirements of this rule, Gulf filed a depreciation study (the **[*2]** Study) in 1987. In the years since the last review, there have been substantial changes in technology, indicating a need for prescribing new rates where appropriate. The Study represents a comprehensive review of all classes of equipment.

RESERVE ADJUSTMENTS

We will approve the adjustments to the depreciation reserve of Gulf contained on Attachment 1. The company plans to retire a cross-bar switch, certain microwave carrier equipment, a portion of its nonfilled buried cable and various computers during the 1987-1989 period. As shown on Attachment 1, the reserve is being restated to allocate these investments between that portion being retired and the balance which is being retained and transferred to other accounts. For filled buried cable, certain station and another cross-bar accounts, the reserve

ATTACHMENT B

is being restated in order to adjust for substantial plant additions and to reduce deficits in various accounts through off-setting them with surpluses and excess salvage from other accounts.

RECOVERY SCHEDULES

We will adopt the amortization schedules listed on Attachment 2 that cover property planned for retirement during the period from 1987 through 1989. Microwave **[*3]** and toll carrier and nonfilled buried cable amortization schedules are being adopted in order to recover completely the investments in retiring plant over this three-year term. The former schedule will recover the remaining net investment in equal annual charges while the latter will recover its investment through write-offs matched to budgeted retirements by year. Rather than continuing the inside wire schedule throughout the up-coming represcription period, we approve the write-off of the full net investment of $54,435 by the end of 1987. Two additional one-year recovery schedules are being set up for the retiring computers and cross-bar switcher. We expect the lower rate base that results from this earlier write-off of retiring plant will help obviate the need for any local service rate increase.

As part of the last depreciation review for Gulf, historic and prospective reserve imbalances were identified and appropriate amortization schedules were approved. The historic reserve imbalance will be eliminated in 1988. Initially, the prospective reserve imbalance was to be amortized over a 14-year term; however, we now believe its entire balance should be written off over the **[*4]** period 1987-1989. The revised schedule which we adopt provides for full amortization by the end of 1989.

DEPRECIATION RATES

As a result of our comprehensive review of the Study, we will prescribe the depreciation rates and components listed on Attachment 3. The company altered its original proposals to concur with recommendations made by our Staff, and the prescribed rates mirror those proposed by Gulf in its revised requests. Gulf requested a January 1, 1987 implementation date for its newly-prescribed depreciation rates. All data and calculations submitted in the Study support this date. We believe this to be an appropriate effective date and will approve the requested implementation date.

Now, therefore, in consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that depreciation reserve accounts of Gulf Telephone Company, its depreciation rates and components, and its amortization schedules are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the attachments appended to this Order.

By ORDER of the Florida Public Service Commission, this 4th day of JANUARY, 1988.

NOTICE **[*5]** OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes (1985), to notify parties of any administrative hearing or judicial review of Commission orders that may be available, as well as the procedures and time limits that apply to such further proceedings. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule *25-22.029, Florida Administrative Code*. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, in the form provided by Rule 25-22.036(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting at his office at 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business **[*6]** on January 25, 1988. In the absence of such a petition, this order shall become effective January 26, 1988, as provided by Rule 25-22.029(6), Florida Administrative Code, and as reflected in a subsequent order.

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

If this order becomes final and effective on January 26, 1988, any party adversely affected may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or by the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure. **[*7]**

ATTACHMENT 1

GULF TELEPHONE COMPANY

RESERVE REALLOCATIONS

				1-1-87
		BOOK		**RESTATED**
	ACCOUNT	**RESERVE**	**TRANSFERS**	**RESERVE**
		$	$	$
221.1	XB Switch	173,090	(173,090)	0
	. . . Retiring		149,861	149,861
	. . . Transfer to 221.0		7,760	7,760
221.0	Digital Switch	459,274	15,469	474,743
	Totals	632,364		632,364
221.3	Microwave/Toll Carrier	350,518	(129,345)	221,173
	. . . Retiring		147,751	147,751
235.0	Paystations	42,103	(14,667)	27,436
236.1	Pvt. Line	14,647	(3,739)	10,908
	Totals	407,268		407,268
242.3	Bur.Ca-Nonfilled	770,008	(227,644)	542,364
	. . . Retiring		227,644	227,644
	Totals	770,008		770,008
261.2	Computers	120,063	(116,493)	3,570
	. . . Retiring		116,493	116,493
	Totals	120,063		120,063

GULF TELEPHONE COMPANY

RESERVE REALLOCATIONS

	ACCOUNT	BOOK RESERVE	TRANSFERS	1-1-87 RESTATED RESERVE
232.1	Ins. Wire	246,930	67,527	314,457
242.4	Bur.Ca.-Filled	774,362	114,378	888,740
	Perry XB Salv.	181,905	(181,905)	0
	Totals	1,203,197		1,203,197

ATTACHMENT 2

GULF TELEPHONE COMPANY

AMORTIZATION SCHEDULES

ACCOUNT	1 - 1 - 87 INVESTMENT	1 - 1 - 87 RESERVE	CURRENT RATE	CURRENT EXPENSE
	$	$		$
Keaton Bch XB	202,592	149,861	8.9%	20,825
Microwave & Toll Carrier	190,000	147,751	7.6%	14,440
Inside Wire	368,892	314,457	10 yr	25,676
Bur.Cable Non-Fill	277,791	227,644	6.9%	15,707
Computers	181,295	116,493	16.7%	30,276
Prior "Historic" Surplus		17,421	5 yr #	(8,711)
Prior "Prospective" Surplus		56,824	14 yr #	(5,116)
		Total=		$93,097

[*8]

GULF TELEPHONE COMPANY

AMORTIZATION SCHEDULES

ACCOUNT	NET SALVAGE	TO BE RECOVERED	PERIOD	EXPENSES 1987	1988	1989
		$		$	$	$
Keaton Bch XB	0	52,731	1 yr	52,731		

ATTACHMENT B

GULF TELEPHONE COMPANY

AMORTIZATION SCHEDULES

ACCOUNT	NET SALVAGE	TO BE RECOVERED	PERIOD	EXPENSES 1987	1988	1989
Microwave & Toll Carrier	4%	34,649	3 yr	11,550	11,550	11,549
Inside Wire	0	54,435	1 yr	54,435		
Bur.Cable Non-Fill	0	50,147	3 yr *	35,310	12,468	2,369
Computers	$10,500	54,302	1 yr	54,302		
Prior "Historic" Surplus		(17,421)	2 yr	(8,711)	(8,710)	
Prior "Prospective" Surplus		(56,824)	3 yr	(18,942)	(18,941)	(18,941)
			Totals=	180,675	(3,633)	(5,023)

ATTACHMENT 3

GULF TELEPHONE COMPANY

1987 STUDY

Depreciation Rates and Components

ACCOUNT		AVERAGE REMAINING LIFE (yrs)	NET SALVAGE (%)	BOOK RESERVE (%)	REMAINING LIFE RATE (%)
212.0	Buildings	21.3	6	28.91	3.1
	CENTRAL OFFICE EQUIPMENT				
221.0	Digital Switch	12.2	0	24.71	* 6.2
221.1	Crossbar Switch (Remaining)	12.2	0	24.71	* 6.2
221.2	COE-Radio	4.1	(6)	75.41	7.5
221.3	COE-Microwave (Remaining)	5.3	4	53.60	* 8.0
221.7	COE-Analog CXR	2.4	10	55.56	14.4
221.8	COE-Digital CXR	8.3	5	26.11	8.3

* Write-off matched to budgeted retirements by year.

From 1-1-84

* Rate reflects reserve reallocation.

GULF TELEPHONE COMPANY

1987 STUDY

Depreciation Rates and Components

ACCOUNT		AVERAGE REMAINING LIFE	NET SALVAGE	BOOK RESERVE	REMAINING LIFE RATE
221.9	Fiber Optic Equip.	10.0	0	0.00	10.0
	STATION EQUIPMENT				
231.1	Station App. (911)	3.0	10	48.48	13.8
235.0	Paystations	5.4	5	41.54	* 9.9
236.1	Lg.Pvt.Line Eq.	4.1	10	36.70	* 13.0
	OUTSIDE PLANT				
241.1	Pole Lines	14.7	(62)	62.71	6.8
241.2	Tower & Twr. Found	15.2	(2)	47.30	3.6
242.1	Aerial Cable	10.4	(5)	39.19	6.3
	Underground Cable				
242.2	Metallic	26.8	(5)	18.80	3.2
	Fiber	20.0	(5)	0.00	5.3
	Buried Cable				
242.3	Nonfilled	5.5	0	81.95	* 3.3
242.4	Filled	19.8	0	20.80	* 4.0
242.5	Drop & Block	15.2	3	25.61	4.7
242.6	Fiber	20.0	(5)	0.00	5.3
244.0	Underground Conduit	44.4	(4)	12.94	2.1
	GENERAL PLANT				
261.1	Furniture	11.6	10	44.58	3.9
261.2	Computer (Remaining)	5.1	3	9.48	* 17.2
261.3	F&O Eq.-Supply	16.3	10	30.60	3.6
261.5	Office Equipment	5.1	0	68.19	6.2
262.1	Official Telephone	6.0	6	85.24	1.5
262.2	Lg. PBX - Official	4.5	1	71.77	6.1
264.1	Passenger Cars	3.6	20	40.17	11.1
264.2	Service Trucks	4.7	30	45.45	5.2
264.3	Heavy Trucks	6.2	10	68.00	3.5
264.4	Heavy Work Mach.	6.3	18	38.63	6.9
264.5	Test Equip.& Tools	5.5	0	54.83	8.2
264.6	Mech. Shop Equip.	4.9	0	53.40	9.5

[*9]

FL Public Service Commission Decisions

End of Document

1988 Fla. PUC LEXIS 2

Florida Public Service Commission

January 26, 1988

DOCKET NO. 871269-TL; ORDER NO. 18736, 88-1 FPSC 440

FL Public Service Commission Decisions

Reporter
1988 Fla. PUC LEXIS 2 *

In re: Request of United Telephone Company of Florida for Acceleration of Amortization Schedules

Core Terms

amortize, notice, depreciate, company, accelerate, imbalance, was

Panel: ; The following Commissioners participated in the disposition of this matter: KATIE NICHOLS, Chairman; THOMAS M. BEARD; GERALD L. GUNTER; JOHN T. HERNDON; MICHAEL McK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING ACCELERATION OF AMORTIZATION SCHEDULES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission of its intent to approve, with modification, the request of United Telephone Company of Florida (United) for acceleration of amortization schedules pursuant to Rules 25-4.175(2)(a) and 25-22.036(4), Florida Administrative Code (F.A.C.). This action is preliminary in nature and will become final unless an appropriate petition for formal hearing is filed pursuant to Rule *25-22.029, F.A.C.*

On December 1, 1987, United filed a request (the Request) seeking authority for accelerating two amortization schedules (collectively, the Schedules). The first schedule, intended to correct a reserve imbalance, was approved by Order No. 12857, issued on January 10, 1984. A reserve imbalance of $3,685,000 was calculated and an amortization period of thirteen **[*2]** years was established, with $283,000 to be expensed annually. At December 31, 1987, the unamortized balance was $2,264,000, and the remaining period was eight years.

By Order No. 16879, issued November 21, 1986, we authorized United to set up the second schedule for amortizing the remaining investment in certain central office equipment ("COE") over a three-year period commencing in 1986. According to the company, there remains to be expensed in 1988 a total of $12,325,704, which reflects the unamortized balance of the original investment and certain additions and retirements that occurred over the amortization period.

The Request seeks approval to record depreciation expenses in 1987 in the amount of the remaining unamortized balances on the Schedules. The company claims that this action would lower future expenses, thereby reducing

ATTACHMENT B

upward pressure on rates. Advancing these expenses into this year is appropriate, in United's view, because 1987 earnings are well within the company's authorized range of return on equity.

Upon review, we will approve United's proposal to make a one-time charge to depreciation of $14,589,704 in 1987. That portion of the Request asking to expense **[*3]** in 1987 the $2,264,000 unamortized investment remaining on the reserve imbalance schedule will be approved. But we cannot authorize the remainder of the Request in its entirety. We agree that United should expense $12,325,704 -- which the company relates to the COE schedule -- in 1987 as additional depreciation; however, we do not find it appropriate to record this entire amount in the COE reserves. Instead, we conclude that the company should record in COE reserves only those reserve deficiencies in COE retiring in 1986 and 1987 and currently scheduled for retirement in 1988. The remainder of the $12,325,704 should be recorded in a nonspecific accumulated depreciation account, and we will determine the specific plant accounts to be affected in United's next depreciation represcription proceeding.

This action, as modified, will comply with our policies of correcting reserve imbalances as rapidly as possible and of accelerating the write-off of plant identified for retirement earlier than projected when these goals can be achieved without adversely affecting rates. For these reasons, we believe that such an opportunity has been presented by United's strong earnings posture and **[*4]** that the Request, with the modification explained above, should be approved.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that United Telephone Company of Florida's request for acceleration of amortization schedules dealing with a reserve imbalance and certain central office equipment is granted subject to the company's recording the amounts calculated in accordance with directions contained in the body of this Order until new depreciation rates are prescribed by this Commission.

By ORDER of the Florida Public Service Commission, this 26th day of JANUARY, 1988.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes (1985), as amended by Chapter 87-345, Section 6, Laws of Florida (1987), to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or *120.68, Florida Statutes*, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing **[*5]** or judicial review will be granted or result in the relief sought.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule *25-22.029, Florida Administrative Code*. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, in the form provided by Rule 25-22.036(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting at his office at 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on February 16, 1988. In the absence of such a petition, this order shall become effective February 17, 1988, as provided by Rule 25-22.029(6), Florida Administrative Code, and as reflected in a subsequent order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is **[*6]** renewed within the specified protest period.

If this order becomes final and effective on February 17, 1988, any party adversely affected may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or by the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT B

FL Public Service Commission Decisions

End of Document

Florida Public Service Commission

November 18, 1988

DOCKET NO. 880860-TL; ORDER NO. 20330, 88-11 FPSC 298

FL Public Service Commission Decisions

Reporter
1988 Fla. PUC LEXIS 1735 *

In re: UNITED TELEPHONE COMPANY OF FLORIDA - 1988 Depreciation Study

Core Terms

cable, amortize, depreciate, switch, plant, retirement, depreciation expense, unrecovered, aerial, radio, bury, recommend, intrastate, interim, offset, fiber

Panel: ; The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD; GERALD L. GUNTER; MICHAEL McK. WILSON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING INTERIM RECORDING OF ADDITIONAL AND INCREASED DEPRECIATION EXPENSES AND OF DEPRECIATION RESERVE ADJUSTMENTS

BY THE COMMISSION:

Notice is hereby given by the Florida Public Service Commission of its intent to approve the request of United Telephone Company of Florida (United) for recording additional depreciation expense, increased depreciation expenses and depreciation reserve adjustments during the interim until final action can be taken on its application for new depreciation rates and adjustment of depreciation reserves pursuant to Sections 350.127 and *364.03, Florida Statutes (1987)*, and Rule 25-4.175, Florida Administrative Code. This action is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for formal proceeding pursuant to Rule 25-22.029.

On June 27, 1988, United filed its triennial depreciation study (Study) requesting our represcription **[*2]** of United's depreciation rates and approval of recovery schedules. United seeks authority to record a one-time charge of $16,125,182 in 1988 depreciation expense to be applied to an outside plant cable reserve deficiency perceived by the company. Additionally, United requests our permission to record in specific accounts certain nonspecific adjustments to United's depreciation reserve. Recording these adjustments to specific accounts will permit the proper allocations, according to United, between intrastate and interstate jurisdictions and access charge categories and will allow proper tax deferral. Moreover, United proposes to correct a reserve imbalance for the

ATTACHMENT B

Aerial, Buried and Underground outside plant cable accounts. Finally, United seeks authority to implement its proposed depreciation rates and recovery schedules beginning January 1, 1989.

United's present bottom-line reserve adjustment arose from three separate actions. By Order No. 19726, issued July 26, 1988, we reduced the company's authorized range of returns on equity for 1988 and 1989 to between 12.5% to 14.5% with a mid-point of 13.5%. Also, we required United to record additional 1988 depreciation expense **[*3]** in an amount calculated to reduce its return on equity by 100 basis points, approximately $10,000,000. The company requests that this expense be applied to its preceived outside plant cable reserve deficiency rather than maintaining it as a nonspecific account entry.

By Order No. 18736, issued January 26, 1988, we authorized United to record an additional depreciation expense of $14,589,704 in 1987. Of that amount, we directed that $2,264,000 be applied to the remaining balance associated with the prospective reserve deficiency. The remainder was ordered to be applied to the remaining unrecovered imbalance associated with 1986-1988 planned retirements. After this adjustment, a residual of $3,687,889 was recorded as a nonspecific central office equipment reserve adjustment. United requests that the residual be recorded as follows: (1) $2,220,583 to the remaining unrecovered investments of 1988 planned central office switching retirements; and (2) $1,467,306 to United's perceived outside plant reserve deficiency.

By Order No. 17429, issued April 10, 1987, we ordered United to record $568,000 of intrastate-only depreciation expense as a nonspecific reserve adjustment to account **[*4]** for savings resulting from the Tax Reform Act of 1986. United proposes that this amount be applied to offset the additional 1988 intrastate amortization of the outside cable reserve deficiency.

Our Staff's preliminary review of the Study tentatively concludes that a reserve deficiency exists in the outside plant cable accounts as a result of the introduction of fiber optics and distributive network architecture. We will approve our Staff's recommendation and grant United's request to allocate the amounts described above as adjustments to the outside plant cable reserve deficiency. However, upon our Staff's completion of its review of the Study, we may order further transfers of these amounts if we conclude that the outside plant cable reserve deficiency was not as large as presently perceived.

The Study identifies a reserve deficiency for Aerial, Buried and Underground Cable Accounts, which our Staff preliminarily calculates to be $27,592,488. As noted above, the impact of fiber optics and distributive network architecture on these outside plant investments indicates that a reserve imbalance calculation should be made for these accounts. For this reason, we will approve our **[*5]** Staff's recommendation that United be permitted to record an additional depreciation expense in the amount of $16,125,182 in 1988 and that this amount be applied to the perceived outside plant cable reserve deficiency. The intrastate portion will be offset by the $568,000 expense dealt with in Order No. 17429. Also, this portion will be offset by any additional amount United is required to record in accordance with Order No. 19726.

The additional depreciation expense and the reserve adjustment transfer ordered above will result in a write-off in 1988 of the entire preliminary outside plant cable reserve deficiency that is presently perceived. Upon our Staff's completion of its review of the Study, any over-recovery experienced in 1988 that is a result of a smaller reserve deficiency being finally calculated will be transferred to other accounts as needed.

We cannot approve United's request to implement its proposed depreciation rates and recovery schedules on a preliminary basis beginning January 1, 1989. We find that the proposed rates for Aerial, Buried and Underground Cable Accounts do not reflect the restated reserve position. We will approve our Staff's recommendation **[*6]** that the rates for the outside plant cable accounts should reflect restated reserves. The rates and recovery schedules that we approve for interim recording are shown on the Attachment to this Order.

A second deficiency of the proposed rates and recovery schedules involves the company's proposal to amortize the net unrecovered investments in near-term planned retirements over a three-year period beginning January 1, 1989. We will approve our Staff's recommendation that the near-term planned retirements be amortized over the remaining period that the equipment will serve the ratepayers. Accordingly, 1989 planned retirements will be recovered in 1989, 1990 planned retirements will be recovered during 1989 and 1990 and 1991 planned retirements will be recovered over the period 1989-1991. See the Attachment.

We note that this recovery will result in apparent over-recoveries for 1989 and 1990 planned retirements of digital switches in the amounts of $2,964,621 and $495,413, respectively, based on United's estimated salvage amounts. We will approve our Staff's recommendation that the 1989 over-recovery be applied to offset the 1989 unrecovered planned retirements of electromechanical **[*7]** switching and radio equipment and that the 1990 over-recovery be applied to offset the 1990 unrecovered planned retirements of electromechanical switching equipment. See the Attachment. These amounts may be transferred at the time we take final action on the Study.

In 1984, we ordered United to record additional intrastate-only depreciation expense in the amount of $8,650,000 in the digital switching account in order to resolve 1983 overearnings. The Study proposes that this intrastate reserve amount be removed from the total digital reserve and amortized in equal amounts to the associated intrastate depreciation expense over the three-year period 1989-1991. We will approve this interim action.

The steps to be taken by United that are ordered above are preliminary in nature and may be effected by final Commission action on the Study. Our Staff will present a final recommendation upon the completion of its review of the Study, and we will order that depreciation expenses be trued-up when we take final action in this docket.

Now, therefore, in consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that the request of United Telephone Company **[*8]** of Florida to begin recording the additional and increased depreciation expenses and the depreciation reserve adjustments discussed in the body of this Order is hereby granted on condition that the Florida Public Service Commission's final decision in this docket will be trued-up by United Telephone Company of Florida to reflect any differences from the directions contained in the body of this Order. It is further

ORDERED that Docket No. ***880860***-TL shall remain open for the purpose of considering the depreciation study filed by United Telephone Company of Florida.

By ORDER of the Florida Public Service Commission, this 18th day of NOVEMBER, 1988.

ATTACHMENT

UNITED TELEPHONE COMPANY

1988 Study

COMMISSION APPROVED FOR INTERIM BOOKING

ACCOUNT	Average Remaining Life (YRS)	Net Salvage (%)	Book Reserve (%)	Remaining Life Rate (%)
General Support Assets				
Passenger Cars	2.2	20	59.0	9.6
Light Trucks	2.7	23	44.4	12.1
Heavy Trucks	5.5	18	41.6	7.4
Special Support Veh.	4.2	10	50.0	9.5
Garage Work Equip.	7 year amortization			
Other Work Equip.	7 year			

UNITED TELEPHONE COMPANY

1988 Study

COMMISSION APPROVED FOR INTERIM BOOKING

ACCOUNT	**Average Remaining Life (YRS)**	**Net Salvage (%)**	**Book Reserve (%)**	**Remaining Life Rate (%)**
	amortization			
Switching Bldgs.	28.2	0	28.1	2.5
Plant/Office Bldgs.	19.2	0	27.0	3.8
Other Bldgs.	13.7	0	21.2	5.8
Towers	4.6	(15)	57.3	12.5
Building Equip.	12.0	(5)	23.3	6.8
Furniture	10 year amortization			
Office Support Equip.	7 year amortization			
Company Communications	5 year amortization			
Gen Purpose Computers	5 year amortization			
Central Office Assets				
Digital 1210's	5.8	4.1	41.8	9.3
Digital Other	10.3	8	13.3	7.6
Electromech. Switching	4.9	0	64.3	7.3
Manual	5.3	20.6	54.1	4.8
Radio Mobile	2.7	(2.5)	73.3	10.8
Radio Other-Digital	3.8	15	68.8	4.3
Circuit				
Analog	2.2	(2.5)	40.4	28.2
Digital	3.9	5	45.6	12.7
Private Line	4.1	7	40.3	12.9
Subscriber	4.1	5	43.7	12.5
Fiber/Termination	5.2	15	6.9	15.0
Tools/Test	3.9	5.4	47.0	12.2
Information Assets				
Station Equipment	7.0	0	24.6	* 14.3
Public Telephone Equip	3.1	3	77.2	6.4
Line Conditioning	3.9	0	75.4	6.3
Subscriber Multiplex	2.5	0	60.1	16.0

* Denotes Whole Life Rate

Melinda Marzicola

ATTACHMENT B

UNITED TELEPHONE COMPANY

1988 Study

COMMISSION APPROVED FOR INTERIM BOOKING

ACCOUNT	Average Remaining Life (YRS)	Net Salvage (%)	Book Reserve (%)	Remaining Life Rate (%)
Cable/Wire Facilities				
Poles	13.7	(45)	41.4	7.6
Aerial Cable Metallic	12.0	(12)	** 32.8	6.6
Aerial Drop	12.0	(12)	** 32.8	6.6
Aerial Cable Fiber	20.0	0	5.7	* 5.0
Underground Cable Met.	13.3	(10)	** 43.5	5.0
Underground Cable Fib.	18.4	(10)	10.6	5.4
Buried Cable Filled	14.9	(5)	** 23.05	5.5
Buried Cable Nonfilled	5.9	(5)	** 64.29	6.9
Buried Drop	14.9	(5)	** 23.05	5.5
Buried Cable Fiber	18.5	(5)	8.7	5.2
Submarine Cable Met.	15.7	(5)	32.9	4.6
Intra-building Network	15.0	(10)	12.1	* 7.3
Aerial Wire	8.1	(35)	90.1	5.5
Underground Conduit	39.5	(5)	22.3	2.1
Amortization Schedules				
Digital Switching				
(1989-1991 Rets.)	3-Year Amortization			
Electromech. Switching				
(1989-1991 Rets.)	3-Year Amortization			
Radio other-Analog				
(1989-1990 Rets.)	2-Year Amortization			
Circuit				
(1989-1990 Rets.)	2-Year Amortization			

[*9]

UNITED TELEPHONE COMPANY

1988 Study

** 1990 overrecovery applied to unrecovered 1990 planned retirement amounts for Electromechanical Switching

Account	1-1-89 Investment $	1-1-89 Reserve $	Expected Salvage $
AMORTIZATION SCHEDULES			
Digital Switching			
(1989 Rets)	$ 15,880,127	$ 8,681,467	$10,163,281
(1990 Rets)	8,721,919	3,984,180	5,233,152
(1991 Rets)	17,271,311	9,217,311	4,663,207
Electromechanical Switching			
(1989 Rets)	17,238,209	14,740,980	810,419
(1990 Rets)	17,956,329	15,384,841	0
(1991 Rets)	9,179,814	8,300,178	0
Radio			
(1989 Rets)	4,915,621	3,563,986	(122,889)
(1990 Rets)	2,319,349	1,638,635	(57,984)
Circuit			
(1989 Rets)	9,340,000	4,576,129	0
(1990 Rets)	7,960,000	3,899,999	0
TOTALS	$110,854,502	$73,987,706	$20,689,186

UNITED TELEPHONE COMPANY

1988 Study

Account	Reserve Transfers $	Net Plant To Be Recovered $	Amortization Period
AMORTIZATION SCHEDULES			
Digital Switching			
(1989 Rets)	* $ (2,964,621)	$ 0	1
(1990 Rets)	** (495,413)	0	2
(1991 Rets)		3,390,616	3
Electromechanical			

* 1989 overrecovery applied to unrecovered 1989 planned retirement amounts for Electromechanical Switching and Radio

UNITED TELEPHONE COMPANY

1988 Study

Account	Reserve Transfers $	Net Plant To Be Recovered $	Amortization Period
Switching			
(1989 Rets)	* 1,686,810	0	1
(1990 Rets)	** 495,413	2,076,075	2
(1991 Rets)		879,636	3
Radio			
(1989 Rets)	* 1,277,811	196,713	1
(1990 Rets)		738,698	2
Circuit			
(1989 Rets)		4,763,871	1
(1990 Rets)		4,060,001	2
TOTALS	$ 0	$16,177,610	

[*10]

End of Document

ATTACHMENT B

1989 Fla. PUC LEXIS 1582

Florida Public Service Commission

October 31, 1989

DOCKET NO. 890203-GU; ORDER NO. 22115, 89-10 FPSC 431

FL Public Service Commission Decisions

Reporter
1989 Fla. PUC LEXIS 1582 *

In re: Application of CITY GAS COMPANY for New Depreciation Rates

Core Terms

depreciate, meter, install, staff, recommend, plastic, lease, deficit, plant

Panel: ; The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER; JOHN T. HERNDON

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER PRESCRIBING DEPRECIATION RATES

BY THE COMMISSION:

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

Rule 25-7.045(7), Florida Administrative Code, adopted November, 1982, requires natural gas companies subject to this Commission's jurisdiction to file a comprehensive depreciation study at least once every five (5) years. In compliance with that rule, City Gas Company (City Gas or utility) filed a depreciation study (study) on February 17, 1989. As part of its filing in this docket, City Gas requested implementation of its proposed depreciation rates, on a preliminary basis, effective as of January 1, 1989. By Order No. 21108, City **[*2]** Gas was authorized on an interim basis to record depreciation rates as requested. The rates approved for interim booking purposes were based on lives and salvages as proposed by the utility. Order No. 21108 also provided that the interim rates would be adjusted, if necessary, upon completion of the review of the study.

The Commission Staff has reviewed City Gas' study and has recommended certain modifications to depreciation rate components. Having reviewed the utility's study and having considered the modifications proposed by Staff, we find that City Gas' rates should be represcribed consistent with the Staff's recommendation. The specific rates and components being approved by this Order are set forth on Attachment 1. Major adjustments to individual accounts are discussed below.

I. Mains and Services (Accounts 376 and 380

ATTACHMENT B

The utility initially did not distinguish between plastic and other mains and services but subsequently supplied the data to make such a separation. City Gas currently has a long-range program of replacement of its galvanized mains and services, and provided detailed information on the project. However, according to Staff the age of the plant being **[*3]** replaced, and the pattern of replacement, does not warrant the use of special amortization schedules. We agree with Staff and find that the allocation of the reserves between Plastic & Other for Mains & Services Accounts shown on Attachment 2 should be approved.

II. Meters, Regulators, and Associated Installations (Accounts 381, 382, 383 and 384)

Installation costs of meters and house regulators have not been maintained in separate accounts as required by Rule *25-7.046, Florida Administrative Code*. Because of the timing, as discussed in this Order, Staff recommended use of one set of depreciation rates to be used for 1989 booking purposes for Accounts 381 and 383 as currently constituted, and a second set to be used after the separation of the four accounts in 1990. This will give the utility the time to separate the investments.

III. Leased Equipment

These are appliances which City Gas leases to customers. As mentioned in Order No. 21108, the utility should be allowed to use their proposed depreciation rates for leased equipment, as constrained by Order No. 21108 (for preliminary implementation of depreciation rates): **[*4]**

The prescription in this Order of depreciation rates does not alter an earlier decision we made in Order No. 17257, in Docket No. 861595-GU, which stated we would not rule upon the appropriateness of costs associated with leased equipment in the Rate Base or Net Operating Income until the utility's next rate case.

IV. Transportation Equipment

Over 90% of the investment in this account is in "light trucks" , and the ratio is not expected to change significantly, which is why our Staff and the utility are not proposing the usual breakdown of the rate into vehicle types. The light trucks are leased vehicles. We approve the life parameter developed from utility-supplied data.

V. Tools, Shop and Garage Equipment

Our Staff indicates that a major portion of this investment currently may not be in use, due to the leasing of vehicles which are not maintained by City Gas. Staff's recommended depreciation parameters and resultant rate are reasonable for the equipment in the account and are approved. Inclusion in Rate Base and NOI of the investments and associated expenses should be reviewed in the next rate case or surveillance.

VI. Reserve Deficit Amortization

As discussed **[*5]** in Staff's recommendation for preliminary action, the write-off of the "Historic" reserve deficit was concluded in 1988. We approved the retention of the associated expense of $ 47,934 with final resolvement to be made in this conclusion of the study. As anticipated at the time of the preliminary action, our Staff continues to recommend that this $ 47,934 be applied to the "Prospective" reserve deficit, which will correct that overstatement of rate base in seven years, rather than the 19 years remaining under the present amortization pattern.

VII. Meters, Meter Installations, House Regulators and House Regulator Installations (Accounts 381, 382, 383 and 384)

As stated in Rule *25-7.046, Florida Administrative Code*, "The accounts listed below directly follow the primary plant accounts prescribed in the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission in the Code of Federal Regulations . . . introducing subdivisions within those accounts for the purpose of uniformity among the companies in depreciation studies."

In the case of Accounts 381 (Meters) , 382 (Meter Installations) , 383 (Regulators) , and **[*6]** 384 (Regulator Installations) , these are Federal Energy Regulatory Commission (FERC) accounts; the only distinction in the Rule of this Commission is to list them specifically to be separately used for depreciation studies. Recognizing that existing records may be lacking detail, the Rule provides "The separation of embedded investments and reserves under prior accounts into balances relating to accounts under subsection (3) may require estimation."

In an earlier depreciation study from this utility, the Meters and Installations section include this statement from their consultant: "The combination of meters and installations into one account makes this account difficult to analyze." There are problems with both life and salvage parameters. Meters and regulators are accounted for as "cradle-to-grave" and may be moved between the customers' premises and the testing or warehouse facilities one or more times before retirement, and then experience approximately zero net salvage. The installations, on the other hand, live approximately the average life of the services (rather than the life of the associated meters or regulators) and experience some negative net salvage (cost of removal) **[*7]** when retired. The monitoring of the combined records is not practicable.

We agree with Staff's recommendation that City Gas will be given six months from the effective date of this Order to bring its accounts into compliance. To provide a transition of depreciation rates from the accounts as they are presently constituted to those after the investments are appropriately separated, Attachment 1 shows rates for use with 1989 activity, and for use after separation in 1990.

Based upon the foregoing, it is

ORDERED by the Florida Public Service Commission that the depreciation rates set forth in Attachment 1 to this Order are hereby approved for City Gas Company. It is further

ORDERED that the $ 47,934 of expense which has been applied to the "Historic" reserve deficit through the year 1988 be added in 1989 and subsequently to the $ 28,166 expense associated with the write-off of the "Prospective" reserve deficit, bringing that total "Prospective" write-off expense to $ 76,100. It is further

ORDERED that the effective date of the depreciation rates approved by this Order is January 1, 1989. It is further

ORDERED that City Gas Company shall bring its Accounts 381 (Meters) , 382 **[*8]** (Meter Installations) , 383 (Regulators) , and 294 (Regulator Installations) in compliance with Rule 25-7.043, Florida Administrative Code, within six months from the effective date of this Order.

By ORDER of the Florida Public Service Commission this 31st day of OCTOBER, 1989.

CITY GAS COMPANY OF FLORIDA

DEPRECIATION RATES

(EFFECTIVE 1-1-89)

ACCOUNT	**AVG. REM. LIFE yr.s**	**AVG. NET SALV. %**	**DEPR. RATE %**
Distribution Plant			
375 Structures	34.0	10	2.2
376 Mains			
(plastic)	35.0	(10)	2.8
(other)	26.0	(10)	2.7

CITY GAS COMPANY OF FLORIDA

DEPRECIATION RATES

(EFFECTIVE 1-1-89)

ACCOUNT	**AVG. REM. LIFE yr.s**	**AVG. NET SALV. %**	**DEPR. RATE %**
397 M&R City Gate	14.0	(5)	3.1
380 Services			
(plastic)	29.0	(35)	4.1
(other)	21.0	(35)	4.3
381 Meters/Installs.	14.9	(2)	* 4.6
381 Meters	14.9	0	# 4.4
382 Meter Installs.	14.9	(5)	# 4.8
383 Regulators/Installs.	16.9	(2)	* 4.1
383 Regulators	16.9	0	# 3.9
384 Regulator Installs.	16.9	(5)	# 4.2
385 Indust. M&R	18.5	(5)	4.0
387 Other	9.1	0	5.6
Leased Plant			
386.5 Wtr Htr.s	7.2	0	7.9
386.6 Dryers	9.6	0	8.3
386.7 Ranges	10.6	0	8.4
General Plant			
390 Structures	22.0	0	3.2
391.1 Office Furn.	13.2	2	6.9
391.2 Office Equip.	8.0	2	11.0
391.3 Computers			
Embedded	3.4	5	16.9
New	6.0	5	15.8
392 Transpt. Equip.			
Embedded	2.9	16	18.4
New	7.0	16	12.0
393 Stores Equip.	10.8	0	5.5

* For use in 1989

For use in 1990 and subsequently, after separation of accounts.

Melinda Marzicola

ATTACHMENT B

CITY GAS COMPANY OF FLORIDA

DEPRECIATION RATES

(EFFECTIVE 1-1-89)

ACCOUNT	AVG. REM. LIFE yr.s	AVG. NET SALV. %	DEPR. RATE %
394 Tools & Shop	8.9	5	6.2
395 Lab. Equip.	14.9	0	4.8
397 Commun. Equip.	6.2	5	7.5
398 Misc. Equip.	5.6	0	8.5

[*9]

Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

CITY GAS COMPANY OF FLORIDA

DEPRECIATION RATES

(EFFECTIVE 1-1-89)

(Reserve allocation - Mains and Services)

ACCOUNT	BOOK RESERVE $	ALLOCATED RESERVE $
376 - Mains	14,796,210	0
" Plastic	0	664,461
" Other	0	14,131,749
380 - Services	6,356,002	0
" Plastic	0	585,451
" Other	0	5,770,551
Totals	$ 21,152,212	$ 21,152,212

FL Public Service Commission Decisions

End of Document

ATTACHMENT B

Florida Public Service Commission

February 21, 1990

DOCKET NO. 890225-TL; ORDER NO. 22585, 90-2 FPSC 375

FL Public Service Commission Decisions

Reporter
1990 Fla. PUC LEXIS 108 *

In re: Investigation of QUINCY TELEPHONE COMPANY for noncompliance with Rule 24-4.017 F.A.C., regarding triennial depreciation study

Core Terms

amortize, depreciate, company, staff, recommend, retirement, wire, was, telephone company, remaining life, aerial, switch, cable

Panel: ; The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER

Opinion

NOTICE OF PROPOSED AGENCY ACTION AND ORDER APPROVING NEW DEPRECIATION RATES, RECOVERY SCHEDULES AND ADJUSTMENT OF DEPRECIATION RESERVE

BY THE COMMISSION:

Notice is hereby given by the Florida Public Service Commission of its intent to approve the request of Quincy Telephone Company (Quincy) for new depreciation rates, recovery schedules and adjustment of depreciation reserves pursuant to Sections 350.127 and *364.03, Florida Statutes (1989)*, and Rule 25-4.175, Florida Administrative Code. This action is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for formal proceeding pursuant to Rule 25-22.029.

Rule *25-4.0175, Florida Administrative Code*, as amended in April of 1988 (the Rule), requires telephone companies to submit depreciation represcription studies within three years from the submission date of the last study. For Quincy, **[*2]** such a study should have been filed by June 7, 1988. According to the Annual Status Report of depreciation-related data submitted June 17, 1988, this study was being prepared in June and was to be submitted upon completion. By letter dated July 29, 1988, Quincy acknowledged its oversight of the Rule and stated its intent to file this study as quickly as possible but committed to no specific date.

Between July and December of 1988, various communications took place between company representatives and our Staff regarding the delinquent study. The company submitted a letter on December 5, 1988, requesting an additional 60 days in which to complete the study, but the company failed to file it within that time period.

On February 8, 1989, Staff sent a letter to Quincy informing it that an investigative docket had been opened regarding its noncompliance with the Rule. Staff gave Quincy 30 days in which to file its study, indicating that, if the

ATTACHMENT B

study was not filed within that period, Staff would recommend that we issue a show cause order. The company filed its study (the Study) on February 24, 1989, requesting represcription of its depreciation rates. The Study represents a comprehensive **[*3]** review of all classes of equipment.

Accompanying the Study is a request for waiver (the Request) of the Rule's requirement that the study be filed within three years of the submission date of the last study. The Request maintains that, since Quincy is not asking that represcribed depreciation rates or amortization schedules be implemented retroactive to 1988, no party would be adversely affected by our granting the Request. Our action below should not be construed as a finding that the tardiness of a depreciation represcription study has no adverse effect on any party. The Rule is quite clear in not starting the three-year filing cycle for studies on the date when current rates were implemented, but rather, on the date when the last study was filed. Accordingly, we find that the Study was some seven months delinquent.

We have exercised patience regarding Quincy's submission of the Study because of the rule change regarding filing deadlines; however, the company is now well aware of the recent amendment of the Rule and we expect no repeat of this filing tardiness in the future. If any company is unable to meet a future submission date, we direct it to contact our Staff before **[*4]** the deadline and to provide adequate justification showing why compliance with the filing deadline is unduly burdensome. We are inclined to grant a one-time waiver in this case, but we believe Quincy should file its next triennial depreciation study no later than June 7, 1991. This will place the company's next depreciation study back on the proper filing cycle.

We approve a transfer in Quincy's depreciation reserve of $ 15,858, which is the surplus associated with the Inside Wire Account, in order to correct the negative reserve of $ 13,083 existing in the Aerial Wire Account. The total Aerial Wire Account reserve imbalance, now amounting to $ 34,960, will be reduced by this transfer to $ 19,102, and this balance will be written-off during 1989 as part of the accumulated reserve adjustments.

By the end of 1989, Quincy's depreciation reserve had been increased by an intrastate amount of $ 459,560. This accumulated amount is composed of the 1987-1989 Bill and Keep surplus, the refund plus interest related to interest synchronization of investment tax credits approved in Order No. 16257 and the 1987 tax savings amount approved in Order No. 18044. We authorize the company to **[*5]** offset the accumulated adjustment of $ 459,560 against the 1989 intrastate depreciation expense of $ 758,237 associated with the recovery schedules approved below.

We will adopt the recovery schedules shown on Attachment 1 to this Order, with the intrastate expenses associated with these schedules being offset by the reserve adjustments approved above. Three of these schedules relate to central office and building equipments planned for retirement in 1989. Customer Premise Equipment and Large PBX Equipment are now on five-year schedules with currently two years remaining until full recovery is achieved. The reserve adjustments discussed above permit achieving recovery in 1989 without increasing the bottom-line depreciation expense. The remaining schedules relate to correcting reserve deficiencies associated with inadequate past recovery; therefore, in our opinion, the associated write-off should be as fast as practicable.

As a result of our comprehensive review of the Study, we will prescribe the depreciation rates and components listed on Attachment 1. In most instances, the prescribed rates mirror those proposed by Quincy; however, there are 5 major differences between the **[*6]** Study's proposals and our Staff's recommendations, and these relate to updating the average age to reflect 1988 activity and to rounding methodology. Areas of substantial differences are discussed below.

The company proposed a 9.9-year remaining life for the E-10 Digital Switch. We will accept our Staff's recommendation of a 9.0-year remaining life for this equipment which is consistent with Quincy's plans and recognizes interim retirements. We consider the two current DCO remote switches as well as the DCO switch being placed into service in 1989 to be flexible and upgradable switches. Our Staff disagrees with Quincy's estimate of life spans of these three switches. We adopt a remaining life which incorporates a 20-year life span with a 1% interim retirement rate.

For the remaining trunk and subscriber Circuit Equipment, Staff could find no support for Quincy's proposal to decrease the service lives underlying the currently-prescribed remaining lives. Therefore, we will adopt a remaining life for this equipment based on these service lives.

A physical inventory of the Poles Account was completed on April 26, 1989, and the company concluded that the investment in poles being **[*7]** retired from service was being understated. Quincy recalculated the amounts that should have been recorded in each of the years 1983-1988 using the inventory results, and found that total retirements had been understated by $ 78,539. The Study does not reflect this adjustment, and we approve our Staff's recommendation that this adjustment be incorporated into the remaining life to be represcribed for this account.

Quincy has no current plans for placing fiber cable. Staff recommends that the company's proposal for the Metallic Cable Account should be modified, based on industry forecasts of substitution of fiber for copper conductors. We approve this recommendation.

During the course of our review of the Study, Quincy completed a field inventory of the Aerial Wire in service at this time. While the company proposes that the remaining net investment be placed on a three-year recovery schedule, it does not have a planned retirement program to replace this remaining wire with cable. Staff recommends that remaining life be based on an estimate of the average age of the remaining investment and a service life that is in line with industry average service lives for this type of **[*8]** plant. We adopt Staff's recommendation and direct that an inventory adjustment of $ 302,091 be made.

Quincy requested a January 1, 1989 implementation date for its newly-prescribed depreciation rates. All data and calculations submitted in the Study support this date. We believe this to be an appropriate effective date and will approve the requested implementation date.

During our review of the Study, we learned that Quincy had not yet implemented the amortization process or the $ 500 expense limit required by Rule *25-4.0178, Florida Administrative Code*, relating to Retirement Units. These actions should have been implemented January 1, 1988. With respect to the amortization of certain General Support Assets and the implementation of a $ 500 expense limit, the company is not in compliance with this rule. It should begin amortization of the affected accounts and subaccounts and implement the expense limit according to this rule as of January 1, 1989. Amortization will also be used for additions to these accounts in the future as long as their individual item cost is more than $ 500.

Now,therefore, in consideration of the foregoing, **[*9]** it is

ORDERED by the Florida Public Service Commission that Quincy Telephone Company's request for a one-time waiver of Rule 25-4.0175(7), Florida Administrative Code, requiring the company to submit its triennial depreciation study by June 7, 1988, is hereby granted. It is further

ORDERED that the next triennial depreciation study required by Rule 25- 4.0175(7), Florida Administrative Code, to be filed by Quincy Telephone Company shall be submitted no later than June 7, 1991. It is further

ORDERED that the depreciation reserve accounts of Quincy Telephone Company, its depreciation rates and components, and its amortization schedules are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the attachment appended to this Order. It is further

ORDERED that Quincy Telephone Company shall comply with Rule *25-4.0178, Florida Administrative Code*, in the manner set forth in the body of this Order. It is further

ORDERED that this docket shall be closed at the expiration of the period established below if a proper protest has not been received. **[*10]**

By ORDER of the Florida Public Service Commission, this 21st day of FEBRUARY, 1990.

ATTACHMENT 1

QUINCY TELEPHONE COMPANY

1989 STUDY

Depreciation Rates and Components

COMMISSION APPROVED

ACCOUNT		(1-1-89) INVESTMENT ()	(1-1-89) BOOK RESERVE ()	AVERAGE REMAINING LIFE (yrs)	NET SALVAGE (%)
2112	VEHICLES				
	Passenger	39,361	9,499	3.8	30
	Light Trucks	145,623	43,839	3.4	20
	Heavy Trucks & Special	177,530	91,139	3.6	15
2121	BUILDINGS				
	Central Office	548,123	235,841	23.0	0
	Plant	196,383	61,635	22.0	0
2212	DIGITAL SWITCHING				
	Stromberg DCO REMOTES	517,000	3,595	16.8	5
	Alcatel E-10	1,502,342	381,031	9.0	5
	New Stromberg DCO	0	0	17.6	5
2231	MOBILE RADIO (EMBEDDED)	40,211	32,786	3.6	0
	MOBILE RADIO (NEW)	0	0	12.0	0

ACCOUNT		(1-1-89) INVESTMENT ()	(1-1-89) BOOK RESERVE ()	AVERAGE REMAINING LIFE (yrs)	NET SALVAGE (%)
2232	CIRCUIT EQUIPMENT				
	Subscriber	376,456	226,344	4.9	0
	Trunk	640,091	433,656	7.6	0
	Optic Electronics	0	0	10.0	0
2351	PAY STATIONS	91,650	72,322	3.7	0
2411	POLES	321,235	82,590	14.3	(50)
	CABLE				
	Fiber	0	0	20.0	0
2421	Aerial	1,841,499	533,378	16.1	(20)
2422	Underground	274,585	106,325	16.9	0
2423	Buried				
	Air-core	451,351	** 404,230	2.8	(10)
	Jelly-Filled	6,647,100	** 1,579,351	19.6	(10)
2424	Submarine (New)	9,981	200	25.0	0
2431	AERIAL WIRE	52,087	** 21,877	5.8	0

** Denotes restated reserve.

ACCOUNT		(1-1-89) INVESTMENT ()	(1-1-89) BOOK RESERVE ()	AVERAGE REMAINING LIFE (yrs)	NET SALVAGE (%)
2441	CONDUIT	145,754	74,732	26.0	0
	TOTAL	14,018,362	4,394,370		

[*11]

ACCOUNT	BOOK RESERVE (%)	REMAINING LIFE RATE (%)
2112		
	24.13	12.1
	30.10	14.7
	51.34	9.4
2121		
	43.03	2.5
	31.39	3.1
2212		
	0.70	5.6
	25.36	7.7

ACCOUNT	BOOK RESERVE (%)	REMAINING LIFE RATE (%)
	--	* 5.4
2231	81.53	5.1
	--	* 8.3
2232		
	60.12	8.1
	67.75	4.2
	--	* 10.0
2351		
	78.91	5.7
2411		
	25.71	8.7
	--	* 5.0
2421	28.96	5.7
2422	38.72	3.6
2423		

* Denotes whole life rate.

ACCOUNT	**BOOK RESERVE (%)**	**REMAINING LIFE RATE (%)**
	** 89.56	7.3
	** 23.76	4.4
2424	0.00	* 4.0
2431	** 42.00	10.0
2441	51.27	1.9

	AMORTIZATION SCHEDULES:				
2116	OTHER WORK EQUIPMENT	263,333	150,606	7	YEAR
2122	FURNITURE	53,512	28,645	10	YEAR
2123.1	OFFICE SUPPORT EQPT	37,170	16,382	7	YEAR
2123.2	OFFICIAL TELEPHONES	36,236	6,469	5	YEAR
2124	COMPUTERS	210,714	92,311	5	YEAR
	TOTAL AMORT. SCHEDULES	600,965	294,413		
	RECOVERY SCHEDULES:				
2121	BUILDINGS-CO RET-89	106,885	45,993	1	YEAR
2215	ELECTROMECH SW.				
	Florida	0	(20,548)	1	YEAR

	Georgia	306,791	227,843	1	YEAR
2220	OPERATOR SYSTEM	0	(1,933)	1	YEAR
	TRUNK CIRCUIT-1989 RET.	20,250	5,812	1	YEAR
	DIGITAL SWITCHING-1989 790,509 RET.	500,998	1	YEAR	
2311	CUST. PREM. EQ.	652,094	484,703	1	YEAR
2341	LARGE PBX	136,767	110,962	1	YEAR
2423	BURIED CABLE RESERVE DEFICIT				
	Air-Core	0	(179,266)	1	YEAR
	Jelly-Filled	0	(257,434)	1	YEAR
2431	AERIAL WIRE RESERVE 0 DEFIC.	(19,102)	1	YEAR	
	TOTAL RECOV. SCHEDULES	2,013,296	1,353,830		
	TOTAL DEPRECIABLE PLANT	16,632,623	6,042,613		

[*12]

2116	AMORTIZATION
2112	AMORTIZATION
2123.1	AMORTIZATION
2123.2	AMORTIZATION
2124	AMORTIZATION
2121	AMORTIZATION

2215	
	AMORTIZATION
	AMORTIZATION
2220	AMORTIZATION
	AMORTIZATION
	AMORTIZATION
2311	AMORTIZATION
2341	AMORTIZATION
2423	
	AMORTIZATION
	AMORTIZATION
2431	AMORTIZATION

FL Public Service Commission Decisions

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[1990 Fla. PUC LEXIS 1658]

Florida Public Service Commission

December 21, 1990

DOCKET NO. 900162-TL; ORDER NO. 23922, 90-12 FPSC 590

FL Public Service Commission Decisions

Reporter
1990 Fla. PUC LEXIS 1658 *

In re: Request by VISTA-UNITED TELECOMMUNICATIONS for new depreciation rates

Core Terms

amortize, depreciate, cable, optic, prototype, fiber, central office, telecommunication, retirement, submarine, electronic, metallic

Panel: ; The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER; FRANK S. MESSERSMITH

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER APPROVING NEW DEPRECIATION RATES, RECOVERY SCHEDULES AND ADJUSTMENT OF DEPRECIATION RESERVE

BY THE COMMISSION:

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

INTRODUCTION

Rule 25-4.0175 (7) requires telephone companies to periodically file a comprehensive depreciation study at least once every three years. In keeping with the requirements of this rule, Vista-United Telecommunications (Vista-United or the Company) filed a depreciation study (the Study) March 3, 1990. In the years since the last review, there have been substantial changes in technology, indicating a need for prescribing new rates where appropriate. Moreover, rate changes are necessary to reflect the different remaining lives of property whose investment **[*2]** has been stratified into sub-accounts since the last review. The Study represents a comprehensive review of all classes of equipment.

IMPLEMENTATION DATE FOR NEW RATES

ATTACHMENT B

Vista-United requested a January 1, 1990 implementation date for its newly-prescribed depreciation rates. All data and calculations submitted in the Study support this date. We believe this to be an appropriate effective date and will approve the requested implementation date.

RESERVE ADJUSTMENTS

In connection with Docket No. 820537 (the Access Charge Docket), the Company was ordered to book Interlata Bill and Keep winnings in the amount of $ 36,000 for 1988 and $ 24,000 for 1989 to a separately identified subaccount for assignment in the next depreciation study. As adopted herein, these amounts go to the one year capital recovery schedule for the Prototype Optic Circuit equipment; grossed up to Total Company with the 0.65 separations factor, the figures for use in the recovery schedule are $ 55,385 and $ 36,923, as shown in Attachment 1. This methodology most closely matches the timing of expenses to life. Furthermore, the $ 99,859 reserve surplus remaining from the previous study should also be included **[*3]** in the Prototype schedule, thus dispensing with the surplus and its negative annual write-off of $ 33,289.

DEPRECIATION RATES AND RECOVERY SCHEDULES

Attachment 2 reflects the depreciation rates herein adopted. These rates and schedules result in an estimated increase in annual depreciation expenses of about $ 376,000 on a total company basis and are based on investments and reserves as of January 1, 1990.

Attachment 3 reflects the Capital Recovery Schedules providing for recovery of the planned near-term retirements of the electronic digital 827 central office, PABXs, central office computers and prototype optic equipment, as well as the coinless public telephone equipment as shown. We regard these retirements as prudent and so order these recovery schedules. Recognizing that there can be interim activity, changes in projected salvage or in exact retirement date, the expenses of these schedules for each month should be determined by dividing the net projected unrecovered plant for that month by the number of months remaining for recovery. This will assure proper recovery during the period of service to the public.

Because of its unique serving area, this Company is on the **[*4]** cutting edge of new technology. This is reflected, in part, by the recommended capital recovery schedules. For example, the Stromberg-Carlson switch (827 office), severely limited in equal access capability and ability to upgrade, is being retired to be replaced with a remote unit hosting off the main DMS-100 switch. This will permit any upgrades to be made directly to that host office, at a resultant savings in cost. The other schedules, for example the retirement of the Prototype Optic equipment, also reflect retirements resulting from the demands of evolving technology.

Major increases in expense resulting from these depreciation rates are in the central office and cable accounts, again the impact of evolving technology. In central office equipment there is relatively less increase as compared to other companies, primarily due to this Company's previous expectations having been comparable with today's.

In the metallic cables, the prime use for this Company is as Distribution plant. The Company is currently carrying on fiber their own locally originating video signals between various locations on the Disney property. One example of the difference in this Company and others **[*5]** is in their Submarine Cable account: it consists of a single metallic cable asset connecting Discovery Island with their network. With the importance of the Discovery Island facility, they expect to replace the existing cooper cable with fiber by 1995 - an earlier date than we might expect for this account from a "typical" company where submarine cables tend more to be generic Feeder facilities, but which is quite logical in this case. Otherwise, the remaining lives of metallic cables are decreasing due to the advent of fiber, as we are seeing elsewhere.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that depreciation reserve accounts of Vista-United Telecommunications, its depreciation rates and components and its amortization schedules are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the attachments appended to this Order. It is further

ORDERED that this docket shall be closed if no protest is filed in accordance with the requirements set forth below.

By ORDER of the Florida Public Service Commission, this 21st day of DECEMBER, 1990.

STEVE TRIBBLE, Director Division of Records **[*6]** and Reporting

VISTA-UNITED TELECOMMUNICATIONS

DEPRECIATION STUDY 1-1-90

(Reserve Transfers)

ACCOUNT OR SOURCE	**CURRENT**	**TO BE TRANSFERRED**	**RESULTANT RESERVE POSITION**
	$	$	$
2232.011 Prototype			
Optic Cct. Equip.	770,670	192,167	962,837
Bill & Keep "Winnings"			
1988	*55,385	(55,385)	0
1989	*36,923	(36,923)	0
Existing Reserve			
Surplus	99,859	(99,859)	0
Total	962,837		962,837

VISTA-UNITED TELECOMMUNICATIONS DEPRECIATION STUDY 1-1-90

COMMISSION APPROVED

ACCOUNT	**REM. LIFE**	**NET SALV.**	**RESV.**	**DEPR RATE**
	yr.s	%	%	%
(General Support Assets)				
2112 Motor Vehicles				
002 Passenger	2.6	20	68.7	4.3
004 Work Veh.	5.6	10	8.3	14.6
005 Trailers (Embed)	15.8	5	90.9	0.3
005 Trailers (New)	20	5	NA	4.8
011 Work (Shared)	6.5	10	4.3	13.1
2116 Work Equip.	5.7	0	62.9	6.5

* Grossed up to Total Company from 36,000 in 1988, 24,000 in 1989

Melinda Marzicola

ATTACHMENT B

	COMMISSION APPROVED			
	REM.	**NET**		**DEPR**
ACCOUNT	**LIFE**	**SALV.**	**RESV.**	**RATE**
2121 Buildings				
001 Butler	12.3	0	14.5	6.9
003 WCC	25	(2)	31.9	2.8
005 Storage Sheds	3.9	0	26.6	18.8
008 Security System	2.5	2	7.0	36.4
2122 Furniture				
001 Ofc. Furn.	TEN YEAR AMORTIZATION			
002 Whse. Furn/Eqp.	SEVEN YEAR AMORTIZATION			
2123 Ofc. Equip.				
002 Official Tel.s	FIVE YEAR AMORTIZATION			
006 Official SL-1	FIVE YEAR AMORTIZATION			
008 Ofc. Equip.	SEVEN YEAR AMORTIZATION			
010 through 023				
Official Comm.	FIVE YEAR AMORTIZATION			
2124 G.P. Computers				
001 PC Equip.	FIVE YEAR AMORTIZATION			
003 IBM Computer	FIVE YEAR AMORTIZATION			
(Central Office Assets)				
2212 Dig. Electronic Sw.				
002 Test Equip.	9.0	0 46.7	5.9	
004 827 C.O.	TWO YEAR CAPITAL RECOVERY SCHEDULE			
005, 006, 007 PABXs	TWO YEAR CAPITAL RECOVERY SCHEDULE			
008 DMS 200	11.1	0	38.9	5.5
009 DMS 100	10.1	0	22.9	7.6
010 Power Plant	8.2	0	65.0	4.3
011, 012 C.O.Comput.s	TWO YEAR CAPITAL RECOVERY SCHEDULE			
011, 012 (New)	6.0	0	0	16.7
016 C.O.Furniture	TEN YEAR AMORTIZATION			
	yr.s	%	%	%
2220 Operator Systems	4.3	0	45.0	12.8
2232 Circuit Equip.				
001 T Carrier	5.7	3	50.9	8.1
003 and 009 Optic	10.0	0	NA	10.0
004 Cct. Equip.	6.1	3	11.4	14.0
O11 Prototype Optic	ONE YEAR CAPITAL RECOVERY SCHEDULE			

ATTACHMENT B

COMMISSION APPROVED

	REM.	**NET**		**DEPR**
ACCOUNT	**LIFE**	**SALV.**	**RESV.**	**RATE**
(Info Orig/Term Assets)				
2351 Public Tel.				
001 Booths	4.0	0	81.7	4.6
002 Paysta. -Coin	4.3	0	97.5	0.6
003 Paysta. Coinless	TWO YEAR CAPITAL RECOVERY SCHEDULE			
004 Paysta. Intell.	4.9	20	5.6	15.2
2362 Tel.Dev.Deaf(Embed)	(FULLY ACCRUED)			0.0
Tel.Dev.Deaf(New)	8.0	0	0 12.5	
(Cable and Wire Assets)				
2422 U.G. Cable				
001 Metallic	11.6	(1)	20.3	7.0
002 Fiber	20	(3)	-	5.2
2423 Bur.Cable				
001 Met.Filled	11.7	(3)	33.3	6.0
002 Fiber	20	(5)	-	5.3
003 Buried NonFill.	5.3	(3)	73.3	5.6
2424 Submarine Ca.				
001 Submarine Met.	4.5	(3)	62.6	9.0
2426 Intrabldg.				
001 Intrabldg. Met.	4.4	(5)	44.5	13.8
New Intrabldg. Fiber	20	(5)	-	5.3
2441 Conduit Systems				
001 Conduit Systems	44	(5)	2.1	2.3
	yr.s	%	%	%
(General Support Assets)				
2112 Motor Vehicles				
002 Passenger	2.6	20	68.7	4.3
004 Work Veh.	5.6	10	8.3	14.6
005 Trailers (Embed)	15.8	5	90.9	0.3
005 Trailers (New)	20	5	0	4.8
011 Work (Shared)	6.5	10	4.3	13.1
2116 Work Equip.	5.7	0	62.9	6.5

	COMMISSION APPROVED			
	REM.	NET		DEPR
ACCOUNT	LIFE	SALV.	RESV.	RATE
2121 Buildings				
001 Butler	12.3	0	14.5	6.9
003 WCC	25	(2)	31.9	2.8
005 Storage Sheds	3.9	0	26.6	18.8
008 Security System	2.5	2	7.0	36.4
2122 Furniture				
001 Ofc. Furn.	TEN YEAR AMORTIZATION			
002 Whse. Furn/Eqp.	SEVEN YEAR AMORTIZATION			
2123 Ofc. Equip.				
002 Official Tel.s	FIVE YEAR AMORTIZATION			
006 Official L-1	FIVE YEAR AMORTIZATION			
008 Ofc. Equip.	SEVEN YEAR AMORTIZATION			
010 through 023				
Official Comm.	FIVE YEAR AMORTIZATION			
2124 G.P. Computers				
001 PC Equip.	FIVE YEAR AMORTIZATION			
003 IBM Computer	FIVE YEAR AMORTIZATION			
(Central Office Assets)				
2212 Dig. Electronic Sw.				
002 Test Equip.	9.0	0	46.7	5.9
004 827 C.O.	TWO YEAR CAPITAL RECOVERY SCHEDULE			
005, 006, 007 PABXs	TWO YEAR CAPITAL RECOVERY SCHEDULE			
008 DMS 200	11.1	0	38.9	5.5
009 DMS 100	10.1	0	22.9	7.6
010 Power Plant	8.2	0	65.0	4.3
011, 012 C.O.Comput.s	TWO YEAR CAPITAL RECOVERY SCHEDULE			
011, 012 (New)	6.0	0	0	16.7
016 C.O.Furniture	TEN YEAR AMORTIZATION			
	yr.s	%	%	%
2220 Operator Systems	4.3	0	45.0	12.8
2232 Circuit Equip.				
001 T Carrier	5.7	3	50.9	8.1
003 and 009 Optic	10.0	0	NA	10.0

COMMISSION APPROVED

ACCOUNT	REM. LIFE	NET SALV.	RESV.	DEPR RATE
004 Cct. Equip.	6.1	3	11.4	14.0
011 Prototype Optic	ONE YEAR CAPITAL RECOVERY SCHEDULE			
(Infor Orig/Term Assets)				
2351 Public Tel.				
001 Booths	4.0	0	81.7	4.6
002 Paysta.-Coin	4.3	0	97.5	0.6
003 Paysta.Coinless	TWO YEAR CAPITAL RECOVERY SCHEDULE			
004 Paysta.Intell.	4.9	20	5.6	15.2
2362 Tel.Dev.Deaf(Embed)	(FULLY ACCRUED)			0.0
Tel.Dev.Deaf (New)	8.0	0	0 12.5	
(Cable and Wire Assets)				
2422 U.G. Cable				
001 Metallic	11.6	(1)	20.3	7.0
002 Fiber	20	(3)	-	5.2
2423 Bur. Cable				
001 Met.Filled	11.7	(3)	33.3	6.0
002 Fiber	20	(5)	-	5.3
003 Buried NonFill.	5.3	(3)	73.3	5.6
2424 Submarine Ca.				
001 Submarine Met.	4.5	(3)	62.6	9.0
2426 Intrabldg.				
001 Intrabldg. Met.	4.4	(5)	44.5	13.8
New Intrabldg. Fiber	20	(5)	-	5.3
2441 Conduit Systems				
001 Conduit Systems	44	(5)	2.1	2.3

[*7]

VISTA-UNITED TELECOMMUNICATIONS

DEPRECIATION STUDY 1-1-90

(Capital Recovery Schedules)

	<--- 1-1-90 --->	ESTD.	TO BE

ACCOUNT	INVEST.	RESERVE	NET SALV.	RECOVERED
	$	$	$	$
(Central Office Assets)				
2212 Dig. Electronic Sw.				
004 827 C.O.	1,090,116	599,785	40,000	450,331
005, 006, 007 PABXs	1,061,068	825,789	190,992	44,287
011, 012 C.O. Comput.s	139,988	77,278	2,800	59,910
2232 Circuit Equip.				
011 Prototype Optic	1,033,902	*962,837	(10,300)	81,365
(Info Orig/Term Assets)				
2351 Public Tel.				
003 Public Coinless	11,956	11,313	0	643

Reflects ordered reserve adjustment (See Attachment 1)

VISTA-UNITED TELECOMMUNICATIONS

DEPRECIATION STUDY 1-1-90

(Capital Recovery Schedules)

		<- EXPENSE ->	
ACCOUNT	**PERIOD**	**1990**	**1991**
Yr.s	$	$	
(Central Office Assets)			
2212 Dig. Electronic Sw.			
004 827 C.O.	2	225,166	225,165
005, 006, 007 PABXs	2	22,144	22,143
011, 012 C.O.Comput.s	2	29,955	29,955
2232 Circuit Equip.			
011 Prototype Optic	1	81,365	0

* Reflects ordered reserve adjustment (See Attachment 1)

VISTA-UNITED TELECOMMUNICATIONS

DEPRECIATION STUDY 1-1-90

(Capital Recovery Schedules)

		<- EXPENSE ->	
ACCOUNT	**PERIOD**	**1990**	**1991**
(Info Orig/Term Assets)			
2351 Public Tel.			
003 Public Coinless	2	322	321
	Total expense:	$ 358,952	$ 277,584

[*8]

FL Public Service Commission Decisions

End of Document

Florida Public Service Commission

January 22, 1991

DOCKET NO. 900599-TL; ORDER NO. 24004, 91 FPSC 1:369

FL Public Service Commission Decisions

Reporter
1991 Fla. PUC LEXIS 67 *

In re: 1990 Depreciation Study of Gulf Telephone Company

Core Terms

amortize, cable, depreciate, furniture, gulf, retirement, remaining life, salvage

Panel: ; The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER; FRANK S. MESSERSMITH

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER CHANGING DEPRECIATION RATES

BY THE COMMISSION:

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

Introduction

Gulf Telephone Company filed a depreciation study on June 29, 1990, in keeping with Rule *25-4.0175, Florida Administrative Code*. Review of Company plans and the status of life, salvage and reserve parameters presented in the study indicates the need for revision of recovery schedules and depreciation rates. The revised schedules and rates are attached to this order.

Implementation Date

The data provided by the Company in the study abuts January 1, 1990, and this date of implementation is proposed by the Company. We **[*2]** concur with the Company's proposal, with the exception of the Circuit Equipment Analog Carrier Account which is updated to include activity through October 1990. The retirement of some 84% of the account in the earlier part of this year changes the life and reserve character of this account significantly, and it is our decision to bring the record for this account to its known status as of November 1, 1990, with the recommended rates, based on this status, to be used from that date forward.

Retirement Units

ATTACHMENT B

Gulf Telephone Company has not implemented the required amortizations for certain General Support Accounts in general plant we adopted in Rule 25-4.0178, Florida Administrative Code, effective January 1, 1988. We find the Company's proposal that amortization be implemented on a going-forward basis, beginning January 1, 1990, appropriate.

Depreciation Reserve

We have reviewed the reserve and find the reserve transfer reflected in Attachment B to be appropriate. In addition, there is a reserve imbalance of $ 244,593 associated with the Metallic Filled Buried Cable Account. This imbalance is based on our present expectation **[*3]** for the replacement of copper cable by fiber and should be written off as fast as practicable. We find a two year period to be appropriate for the write-off of this deficiency.

The depreciation rates are shown on Attachment A, and the amortization and recovery schedules are on Attachment C.

Account 22320 Circuit Equipment -- Analog Carrier

The retirement of $ 60,382 from this account during the early part of 1990 has resulted in $ 30,891 of plant in service and $ 24,082 in associated reserve as of November 1, 1990. Based on engineering estimates from the Company, we find a five year remaining life for this equipment to be appropriate. The rate of 4.4% should be implemented as of November 1, 1990.

Account 2311 Station Apparatus-Embedded

We concur with the Company thinking that recovery over the estimated remaining period of the useful life is appropriate. We concur with the 0 net salvage estimate. We find that the monthly expense to be booked should be calculated by dividing the net unrecovered investment by the number of months remaining before retirement.

Cable Accounts

Our assumptions in this order are based on the recognition of industry forecasts for the replacement **[*4]** of copper cable installations by fiber, taken with the premise that the impact on the smaller companies will generally lag that experienced by the larger companies which serve the metropolitan areas. The projections contained herein are in general accord with the concept of fiber to the home (or curb) in the second decade of the 21st century.

Account 2421 Aerial Cable

This order is rooted in the view or projection that final that final retirement of copper cable used for distribution will be approximately the year 2017. We find a remaining life of 13.8 years to be appropriate. We accept the Company proposed future net salvage of negative 10%.

Account 2422 Underground Cable

Fiber technology can be expected to have a significant impact upon the equipment associated with this account. Almost 87% of the investment in this account is associated with cable used as feeder. We find a remaining life of 20 years to be appropriate. This is consistent with a projected phase-out by about 2015.

Account 2423 Buried Cable

Non-Filled: Industry-wide, the installation of non-filled cable typically was discontinued in the early to mid-seventies. The last installation by Gulf is recorded **[*5]** as 1974. Currently, many equipment failures and consequent retirements of this cable are being reported by various companies, with replacements by filled cable. Gulf is not reporting as much difficulty in this regard as some others. This is reflected in their budgeted retirements of $ 106,000 total in this account for 1990 through 1992. The Company indicates that retirements thus far in 1990 are on target, compared to the budget and plant additions underway. These facts are in line with the Company proposed remaining life value of 7.7 years and the current age of 20.7 years.

Filled: The current average age of the investment in this account is 7.8 years. Remaining life is based on a scenario in which phase-out occurs by about 2017. Combined with the $ 3-23 curve this gives a remaining life of 15.5 years.

For both filled and non-filled, net salvage of negative 5% is recommended because of the cost associated with the disconnection of cable from use along with closure of pedestals, removal of terminals or both.

Based on the foregoing, it is hereby

ORDERED by the Florida Public Service Commission that the status of life, salvage and reserve parameters described above and more **[*6]** fully in the attached schedules be implemented. It is further

ORDERED that the date for implementation for the new rates and recovery schedules be January 1, 1990, except for the Circuit Equipment Analog Carrier Account, for which the implementation date shall be November 1, 1990. It is further

ORDERED that Gulf Telephone Company implement the required amortization for certain General Support Accounts pursuant to Rule *25-4.0178, Florida Administrative Code* on a going-forward basis beginning January 1, 1990. It is further ORDERED that Gulf make the adjustment to depreciation described in the body of this Order and the schedules attached. It is further

ORDERED that if no protests are filed pursuant to the requirements below, this docket shall be closed at the conclusion of protest period.

By ORDER of the Florida Public Service Commission, this 22nd day of JANUARY, 1991.

ATTACHMENT A

GULF TELEPHONE COMPANY

1990 DEPRECIATION STUDY

COMMISSION APPROVED

AMORTIZATION SCHEDULES

2115	MECHANICAL SHOP EQ.	7	Year	Amortization
2116	TOOLS, WORK EQPT.Post'89	7	Year	Amortization
	Heavy Work Eq. '88 & prior	5	Year	Amortization
	Test Eq.&Tools '88 & prior	5	Year	Amortization
	Test Eq. & Tools '89 Adds	6	Year	Amortization
2122	FURNITURE & OFFICE SUPPLY	10	Year	Amortization
	Furniture '88 & prior	8	Year	Amortization
	Furniture '89 Adds	9	Year	Amortization
	Furn.& Ofc.Supply'88&prior	8	Year	Amortization
2123	OFFICE SUPPORT EQUIPMENT	7	Year	Amortization

AMORTIZATION SCHEDULES

	Ofc.Sprt.Eq.'88 & prior	5	Year	Amortization
	Ofc.Sprt.Eq.'89 Adds	6	Year	Amortization
	OFFICE COMM. EQUIPMENT	5	Year	Amortization
	Co.Comm.Eq.Appar.'88 &prior	3	Year	Amortization
	Co. Comm Eq.PBX'88 & prior	3	Year	Amortization
2124	GENERAL PURPOSE COMPUTERS	5	Year	Amortization
	1988 and Prior	3	Year	Amortization
	1989 Addition	4	Year	Amortization

RECOVERY SCHEDULE

2311	STATION APPAR. EMB.	1	Year(Approximate)	Amortization
	RESERVE DEFICIT	2	Year	Amortization

[*7]

ATTACHMENT B

GULF TELEPHONE COMPANY

1990 DEPRECIATION STUDY

COMMISSION APPROVED

AMORTIZATION SCHEDULES

2115	MECHANICAL SHOP EQ.	7	Year	Amortization
2116	TOOLS, WORK EQPT.Post'89	7	Year	Amortization
	Heavy Work Eq. '88 & prior	5	Year	Amortization
	Test Eq.&Tools '88 & prior	5	Year	Amortization
	Test Eq. & Tools '89 Adds	6	Year	Amortization
2122	FURNITURE & OFFICE SUPPLY	10	Year	Amortization
	Furniture '88 & prior	8	Year	Amortization
	Furniture '89 Adds	9	Year	Amortization
	Furn.& Ofc.Supply'88&prior	8	Year	Amortization
2123	OFFICE SUPPORT EQUIPMENT	7	Year	Amortization

AMORTIZATION SCHEDULES

	Ofc.Sprt.Eq.'88 & prior	5	Year	Amortization
	Ofc.Sprt.Eq.'89 Adds	6	Year	Amortization
	OFFICE COMM. EQUIPMENT	5	Year	Amortization
	Co.Comm.Eq.Appar'88&prior	3	Year	Amortization
	Co. Comm Eq.PBX'88 & prior	3	Year	Amortization
2124	GENERAL PURPOSE COMPUTERS	5	Year	Amortization
	1988 and Prior	3	Year	Amortization
	1989 Addition	4	Year	Amortization
	RECOVERY SCHEDULE			
2311	STATION APPAR. EMB.	1	Year(Approximate)	Amortization
	RESERVE DEFICIT	2	Year	Amortization

ATTACHMENT C

GULF TELEPHONE COMPANY

1990 DEPRECIATION STUDY **[*8]**

COMMISSION APPROVED

AMORTIZATION SCHEDULES

2115	MECHANICAL SHOP EQ.	7	Year	Amortization
2116	TOOLS, WORK EQPT.Post'89	7	Year	Amortization
	Heavy Work Eq. '88 & prior	5	Year	Amortization
	Test Eq.&Tools '88 & prior	5	Year	Amortization
	Test Eq.& Tools '89 Adds	6	Year	Amortization
2122	FURNITURE & OFFICE SUPPLY	10	Year	Amortization
	Furniture '88 & prior	8	Year	Amortization
	Furniture '89 Adds	9	Year	Amortization
	Furn.& Ofc.Supply'88 &prior Ofc.Supply'88 &prior	8	Year	Amortization
2123	OFFICE SUPPORT EQUIPMENT	7	Year	Amortization

AMORTIZATION SCHEDULES

	Ofc.Sprt.Eq.'88 & prior	5	Year	Amortization
	Ofc.Sprt.Eq.'89 Adds	6	Year	Amortization
	OFFICE COMM. EQUIPMENT	5	Year	Amortization
	Co.Comm.Eq.Appar'88. &prior	3	Year	Amortization
	Co. Comm Eq.PBX'88 & prior	3	Year	Amortization
2124	GENERAL PURPOSE COMPUTERS	5	Year	Amortization
	1988 and Prior	3	Year	Amortization
	1989 Addition	4	Year	Amortization
	RECOVERY SCHEDULE			
2311	STATION APPAR. EMB.	1	Year(Approximate)	Amortization
7	RESERVE DEFICIT	2	Year	Amortization

FL Public Service Commission Decisions

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1991 Fla. PUC LEXIS 66

Florida Public Service Commission

January 22, 1991

DOCKET NO. 891373-TL; ORDER NO. 24005, 91 FPSC 1:375

FL Public Service Commission Decisions

Reporter

1991 Fla. PUC LEXIS 66 *

In re: INDIANTOWN TELEPHONE SYSTEM, INC. - 1990 Depreciation Study

Core Terms

metallic, cable, was, fiber, switch, bury, amortize, digital, carrier, upgrade, retire, fill, depreciate, imbalance, write-off

Panel: ; The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER; FRANK S. MESSERSMITH

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER CHANGING DEPRECIATION RATES

BY THE COMMISSION:

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

The last comprehensive depreciation represcription for Indiantown Telephone Company, Inc. (Indiantown or the Company) was made in 1987. Pursuant to Rule *25-4.0175, Florida Administrative Code*, Indiantown filed the study being considered in this docket. Rates prescribed in the 1987 study were remaining life rates with recovery schedules for the unrecovered cost of submarine cable and analog carrier planned for near-term retirement. In addition, the amortization period for inside wire was shortened to permit recovery by year-end 1988.

Upon **[*2]** review of the latest study, it is apparent that the Company should be allowed to revise its depreciation rates and recovery schedules. The processor portion of the Indiantown digital switch was replaced in early 1990. The changeout occurred as part of an upgrade from "release 14" software to "release 17." As a result, there was an unrecovered cost of $ 58,402. We find that the apparent reserve surplus existing in the remaining digital switching account should be applied to offset this deficiency. In addition, there is a calculated reserve deficit associated with the Stuart West digital remote switch, and reserve deficiencies exist in the metallic cable accounts due to the impact of fiber extent technology is affecting the estimated life of equipment, the Company should be permitted to react accordingly and the deficits resulting from these shortened perceived lives should be written-off as fast as economically practicable. A three year write-off period for this net deficiency appears to be practicable for this company. The annual write-off amount will be $ 37,477. As a result of the corrective action discussed above, each affected account's reserve is placed at its theoretically **[*3]** correct level as shown on Attachment 2, page 7.

ATTACHMENT B

The Company proposed to apply the deferred CIAC revenues from Order No. 21474 to the write-off of the net imbalance associated with only the retired processor and the filled metallic buried cable account. This action does not provide any corrective action for the calculated deficiencies associated with the metallic underground cable and the metallic non-filled buried cable accounts and would further bring the reserve associated with the filled buried cable account to an amount exceeding its calculated theoretically correct position. In addition, upon reviewing the earnings condition of the Company, we are of the opinion that it is not necessary to offset these resultant write-off expenses with the deferred CIAC revenues.

In the course of review of this study, the Company agreed on life and salvage parameters for all accounts. The only remaining issue relates to (1) the amount of reserve imbalance and its write-off method; and, (2) the January 1, 1990 statement of investment and reserve positions for the digital carrier and metallic filled buried cable accounts. For the later, during the course of review, it became apparent that **[*4]** $ 72,301 had been inadvertently booked to the metallic filled buried cable account in 1989 rather than to the correct digital carrier account.

Life factors recommended reflect the prospective impacts of network upgrading throughout the State; an example is the effect of the move to the Synchronous Optical Network. The expected life of upgradable digital switches is problematic. The Technology Futures Study, for example, suggests that the current upgradable generation might live until about 2013-2014. That may be optimistic, it is not unusual for technologies to be superseded before expected. The pattern of upgrade retirements as projected by various sources varies because the time of upgrade is still ahead of us. A blending of projections of retirements comports with about 30% of the current embedded investments, including processor, having been retired by about 2004.

Stuart West is currently a remote digital switch homing on the host in Indiantown. In this area, new subdivisions and three hotels are planned. At the time the current study was submitted, it was anticipated that this remote would need to be replaced during 1990 to provide for the expected growth. At this time **[*5]** however, some lots have been sold, but no building has begun. The status of this situation should be monitored closely by the Company, and when circumstances change and plans are firmed up, the Company should petition for the appropriate recovery treatment for any anticipated unrecovered investment.

Life factors for the metallic cable accounts reflect the scenario of phasing out interoffice facilities by about 2000 and feeder by about 2014. Distribution facilities would be expected to have phased-out very few years later -- possibly in the 2017 period. These projections are in general accord with the concept of fiber to the home (or curb) in the second decade of the 21st century.

A new direct buried fiber interoffice toll route was placed in service in November. This route goes from Indiantown to the Southern Bell tandem switch in West Palm Beach. The T-carrier serving this route was at capacity, leaving the Company the alternative of adding more T-carrier or replacing the facility with fiber. It was determined that the economical choice was to install fiber. The T-carrier facility was retired but will be reused for local service. According to the company, the fiber electronics **[*6]** equipment (multiplexing) installed is SONET compatible.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Indiantown Telephone Company, Inc. revise its depreciation rates and recovery schedules as generally described above and reflected more specifically in the attachments to this Order. It is further

ORDERED that the revisions of the depreciation rates and recovery schedules be made effective January 1, 1990. It is further

ORDERED that the corrective reserve measures illustrated in Attachment 2 be implemented and the net reserve imbalance of $ 112,430 be written off over a three year period. It is further

ORDERED that this docket be closed at the conclusion of the protest period if no protests are filed pursuant to the requirement below.

By ORDER of the Florida Public Service Commission, this 22nd day of JANUARY, 1991.

ATTACHMENT 1

INDIANTOWN TELEPHONE SYSTEM, INC.

1990 STUDY

COMMISSION APPROVED

	ACCOUNT	**A.R.L.**	**SAL (yr)**	**NET RES. (%)**	**BK. RATE (%)**	**R.L. (%)**
2112	VEHICLES					
	Passenger cars	6.0	10	36.67	8.9	
	Light Trucks	4.9	7	35.74	11.7	
2116	TOOLS & EQUIP.		7-Year Amortization			
2116.1	CONSTRUCTION EQUIP.	6.6	10	82.56	1.1	
212	BUILDINGS					
		Office	23.0	10	32.94	2.5
	Single Unit	24.0	0	16.16	3.5	
	Plant	29.0	5	17.57	2.7	
2122	OFFICE FURN.		10-Year Amortization			
2123	OFFICE EQUIP.					
	Office Machines		7-Year Amortization			
	Official Telephones		7-Year Amortization			
2124	COMPUTER EQUIP.		5-Year Amortization			
2212	DIGITAL SWITCHING					
	Digital Sw./Process	12.6	0	20.62	***	6.3
	Digital Proces.(Emb)		1-Year Amortization			
	Stuart West	3.0	0	81.10	***	6.3
2232	CARRIER					
	Analog Carrier	3.4	(5)	74.59	8.9	
	Digital Carrier	6.6	0	22.25	11.8	
	Fiber	10.0	0	0.00		10.0
2351	PUBLIC TELEPHONES	3.3	0	83.21	5.1	
2362	DEVICES FOR THE DEAF	3.2	0	90.12	3.1	
	Terminating Equipment	6.0	0	41.76	9.7	
2411	POLES	11.9	(60)	62.55	8.2	
2421	AERIAL CABLE					
	Metallic	12.9	(30)	43.57	***	6.7

*** ## Denotes whole life rate.

Denotes Staff Recommended restated reserve.

COMMISSION APPROVED

	ACCOUNT	A.R.L.	SAL (yr)	NET RES. (%)	BK. RATE (%)	R.L. (%)	
	Fiber	20.0	(15)	0.00	5.8		
2422	UNDERGROUND CABLE						
	Metallic	13.9	(5)	31.33	***	5.3	
	Fiber	20.0	(5)	0.00		5.3	##
2423	BURIED CABLE						
	Metallic Non-Filled	5.4	(5)	67.20	***	7.0	
	Metallic Filled	14.3	(5)	27.78	***	5.4	
	Fiber	20.0	(5)	0.00	5.3	##	
2441	CONDUIT	47.0	(5)	6.21	2.1		

[*7]

ATTACHMENT 2

INDIANTOWN TELEPHONE SYSTEM, INC.

1990 STUDY

CORRECTIVE RESERVE TRANSFERS

	1/1/90 Book Reserve	Theoretical Reserve	Calculated Reserve Imbalance	Commission Approved Restated Reserve
Digital Switch	$ 263,129	$ 194,800	$ 68,329	$ 194,800
Processor	65,416	123,617	(58,201)	123,617
Stuart West	24,097	66,008	(41,911)	66,008
Aerial Cable Metallic	30,126	23,533	6,593	23,533
Underground Cable Metallic	23,321	40,504	(17,183)	40,504
Buried Cable				
Metallic Air	274,859	285,558	(10,699)	285,558
Metallic Filled	795,757	855,115	(59,358)	875,200

	1/1/90 Book Reserve	Theoretical Reserve	Calculated Reserve Imbalance	Commission Approved Restated Reserve
Total Net Imbalance			(112,430)	

FL Public Service Commission Decisions

End of Document

1992 Fla. PUC LEXIS 277

Florida Public Service Commission

February 3, 1992

DOCKET NO. 910565-TL; ORDER NO. 25679, 92 FPSC 2:91

FL Public Service Commission Decisions

Reporter
1992 Fla. PUC LEXIS 277 *

In re: Depreciation study for QUINCY TELEPHONE COMPANY

Core Terms

depreciate, amortize, cable, retire, telephone, salvage

Panel: ; The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; SUSAN F. CLARK; J. TERRY DEASON; BETTY EASLEY

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER SETTING DEPRECIATION RATES

BY THE COMMISSION:

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

Rule *25-4.0175, Florida Administrative Code* (the Rule), requires telephone companies to submit depreciation studies within three years of the submission date of the last study. Quincy Telephone Company's (Quincy or the Company) last study was filed February 24, 1989, inadvertently seven months delinquent. By Order No. 22585, issued February 21, 1990 (the Order), we granted the Company a one-time waiver of the Rule; but, in order to place the Company back on its proper filing cycle, we directed Quincy to file its next triennial depreciation study no later that June **[*2]** 7, 1991. The present study (the Study) was filed May 2, 1991, in compliance with that Order. Upon review of the Company's plans and the status of life, salvage, and reserve parameters, we find that revision of recovery schedules and depreciation rates is appropriate at this time.

As shown on Attachment 1, the net bottom line reserve deficit is $ 410,091. As a result of our findings in Docket 910461-TL, concerning the disposition of Quincy's 1990 and 1991 overearnings, we determined, by Order No. 24940, issued August 20, 1991, that $ 250,359 (total company) is available from 1990 earnings. An additional $ 70,145 (total company) was placed in an unclassified reserve account pending resolution of this Study. Further, we approved an additional $ 150,000 (intrastate) as an offset to reserve deficit; which will gross up to approximately $ 208,681 total company. Using $ 410,091 of these funds, along with the transfers from accounts showing a surplus will bring all accounts into balance with the reserve position attained if the life and salvage components presently seen as correct had been in use historically. Any residual overearnings will be addressed in Docket No. 910461-TL. **[*3]**

Based on the results of the Study, we find that the appropriate life and salvage parameters and resulting depreciation rates for Quincy are those set forth in Attachment 2, attached hereto. The major changes in depreciation rates are in those accounts representing assets subject to displacement by expected technological innovations; the Central Office and Outside Plant accounts.

Further, we are approving a two-year capital recovery schedule for the buried cable planned for retirement in 1992, as shown in Attachment 3. To account for any interim activity or changes in projected net salvage, the expense for this recovery schedule should be developed each month by dividing net plant for that month by the months remaining in the recovery schedule.

Quincy requested a January 1, 1991, implementation date for its newly prescribed depreciation rates. All data and calculations submitted in the Study support this date. We believe this to be an appropriate effective date and hereby approve the requested implementation date.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the depreciation reserve accounts of Quincy Telephone Company, its depreciation **[*4]** rates and components, and its amortization schedules are hereby adjusted and represcribed as set forth in the body of this Order and as more particularly identified in the attachments appended to this Order. It is further

ORDERED that the implementation date of the new depreciation rates shall be January 1, 1991. It is further

ORDERED that this docket shall be closed at the expiration of the period established below if a proper protest has not been received.

By ORDER of the Florida Public Service Commission, this 3rd day of FEBRUARY, 1992.

ATTACHMENT 1

QUINCY TELEPHONE CO.

DEPRECIATION STUDY 1-1-91

(Reserve Adjustments)

(Using Overearnings and Reserve Transfers)

		1-1-91	
	TRANSFERS	**ADJUSTED**	
ACCOUNT	**In (Out)**	**< RESERVE ->**	
	$	$	%
General Support Assets:			
Autos	6,668	7,268E	16.00
(After retire of the Ply.Reliant)			
Lt. Tk.s	15,230	37,228E	26.80
(After retire of the F250 and two S-10s)			
Hvy. Tk.s	(3,098)	18,955E	8.50
(After retire of the 1980 Ford)			
C.O.Bldg.s	57,838	325,379	44.70
Plt.Bldg.s	(12,232)	29,640	20.80

ACCOUNT	TRANSFERS In (Out)	1-1-91 ADJUSTED < RESERVE ->	
Paysta.s	(25,952)	34,687	52.27
General S.A. totals =	38,454	453,157	
C.O.E.:			
Alcatel Sw.	7,022	687,058	42.76
(E-10 & Talquin Remote)			
SC Sw.	100,131	212,563	13.10
(DCO, Attapulg., SC Remotes)			
Radio	(12,299)	24,589	61.15
Subscr.Cct.	(240,263)	0	0.00
Analog	175,479	175,479	72.35
Digital	35,852	35,852	28.50
Trunk Cct.	(67,271)	420,595	64.25
Concentrator	(7,736)	7,116	5.00
C.O.E. totals =	(9,085)	1,563,252	
O.S.P.:			
Poles	78,904	177,499	58.41
Cables -			
Aer. Met.	335,453	942,341	50.08
U.G. Met.	49,564	175,331	61.74
Bur.NonF.	(352,971)	0	0.00
91-92 Rets	132,164	132,164	94.00
Remaining	156,253	156,253	77.50
Bur.Fill.	(33,528)	2,163,507	26.70
Submarine	386	1,186	11.80
Aer. Wire	21,341	18,699	39.00
Conduit	(6,844)	73,441	48.00
O.S.P. totals =	380,722	3,840,421	

Net of ordered
corrective transfers from
overearnings (Total Company) = 410,091

[*5]

ATTACHMENT 2

QUINCY TELEPHONE CO.

DEPRECIATION STUDY 1-1-91

(Rates and Components)

<- - - - ORDERED - - ->

ACCOUNT	REM. LIFE yr.s	NET SALV. %	ADJ. RESV. %	DEPR. RATE %
(General Support Assets)				
2112 Motor Vehicles				
.10 Passenger	4.0	20	16.00	16.0
.20 Lt. Tks.	4.0	20	26.80	13.3
.30 Hvy.Tks.	9.0	15	8.50	8.5
2121 Buildings				
.10 C. O.	21	7	44.70	2.3
.20 Plant	24	0	20.80	3.3
(Assets Amortized by Rule)				
2116 Work Equip.	SEVEN	YEAR	AMORTIZATION	
2122 Furniture	TEN	YEAR	AMORTIZATION	
2123 Ofc. Equip.	SEVEN	YEAR	AMORTIZATION	
.20 Comp. Comm.	FIVE	YEAR	AMORTIZATION	
2124 Gen.Purp.Comp.	FIVE	YEAR	AMORTIZATION	
(Central Office Assets)				
2212 Dig. Electronic Sw.				
.11 & .21 Alcatel	5.3	0	42.76	10.8
.10 & .20 S. C.	11.0	0	13.10	7.9
2231 Radio	3.5	0	61.15	11.1
2232 Circuit Equip.				
.10 Subscriber				
Analog	3.5	0	72.35	7.9
Digital	7.0	5	28.50	9.5
.20 Trunk	2.5	0	64.25	14.3
.30 Concentrator	9.5	0	5.00	10.0
.325 Optic	10.0#	0	NA	10.0
(Info Orig/Term Assets)				
2351 Paystations	4.3	0	52.27	11.1
(Outside Plant)				
2411 Poles	12.9	(50)	58.41	7.1
2421 Aerial Cable				
.00 Metallic	11.1	(30)	50.08	7.2
.xx Fiber	20.0#	(5)	NA	5.3
2422 U.G. Cable				
.10 Metallic	10.3	(5)	61.74	4.2
.xx Fiber	20.0#	(5)	NA	5.3
2423 Bur. Cable				
.10 Met.AirCore(Rem)	5.0	(5)	77.50	5.5
.10 Met.AirCore(91-92 Rets)		2 YR. RECOV. SCHED.		

.20 Met. Filled	13.5	(5)	26.70	5.8
.30 Fiber	20.0#	(5)	NA	5.3
2424 Submarine Ca.	22.0	(2)	11.80	4.1
2431 Aerial Wire	7.4	(50)	39.0	15.0
2441 Conduit	26.0	0	48.00	2.0

[*6]

#

ATTACHMENT 3

QUINCY TELEPHONE CO.

DEPRECIATION STUDY 1-1-91

(Two year Recovery Schedule for)

(1991-1992 Buried Cable Retirements)

	RETIRING	NET		TO BE	
ACCOUNT	**INVEST.**	**SALVAGE**	**RESERVE**	**RECOVERED**	**PERIOD**
	$	$	$	$	yr.s
Buried Cable					
Non-filled	140,600	(7,030)	132,164	15,466	2

FL Public Service Commission Decisions

Whole Life

1993 Fla. PUC LEXIS 1371

Florida Public Service Commission

October 25, 1993

DOCKET NO. 921278-TL; ORDER NO. PSC-93-1554-FOF-TL, 93 FPSC 10:337

FL Public Service Commission Decisions

Reporter
1993 Fla. PUC LEXIS 1371 *

In Re: Review of Capital Recovery Requirements of Indiantown Telephone System, Inc.

Core Terms

cable, depreciate, amortize, salvage, bury, metallic, retirement, carrier, aerial, revise, has, remaining life, flowback, deferred income, calculate, companies, replace, defer, fiber

Panel: ; The following Commissioners participated in the disposition of this matter: J. TERRY DEASON, Chairman; SUSAN F. CLARK; JULIA L. JOHNSON; LUIS J. LAUREDO

Opinion

NOTICE OF PROPOSED AGENCY ACTION

ORDER REGARDING DEPRECIATION

BY THE COMMISSION:

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

I. THE FILING

Rule *25-4.0175, Florida Administrative Code*, requires that telephone companies file a comprehensive depreciation study at least once every three years from the submission date of the previously filed study. Indiantown has filed a study pursuant to the Rule. Since the time of the last represcription, net plant balances and technological impacts on life and salvage have changed. In addition, current Company plans are to replace remaining aerial and air core buried metallic cables with filled buried metallic cable by year-end 1994. These **[*2]** circumstances indicate that some rates may need revision.

II. IMPLEMENTATION DATE

All supportive data and calculations have been made abutting the Company's requested implementation date of January 1, 1993 which we find to be appropriate.

ATTACHMENT B

III. RESERVE TRANSFERS

As of January 1, 1993, the Aerial Metallic Cable account, (Account 2421) shows a negative reserve balance of $ 29,536. The cause for this deficiency was a large retirement (about 87% of the account investment) occurring in 1991. This unusual activity was unforeseen at the time of the last study and, therefore, was not considered in the design of the currently prescribed depreciation rate. Upon review, we find that the apparent reserve surplus which exists in Construction Equipment, Account 2116.1, shall be transferred to help alleviate the aerial cable deficiency. This will leave a residual deficiency of $ 34,303 in the Aerial Cable account. In addition, there is a perceived deficiency of $ 213,455 in the Buried Cable-Filled account.

The Company's Earnings Surveillance Report for 12 month ended June 30, 1993 indicates an achieved return on equity (ROE) of 20.33%, 6.63% above the maximum authorized **[*3]** ROE. This equates to approximately $ 200,000 in excess revenues. Based on seven months of actual financial data, we have forecasted the Company's earnings for 1993. Included in the forecast is the recently approved intraLATA toll rate reduction of $ 208,000. Additionally, it appears that the Company's earnings will improve even more by the end of the year. The Company submitted a letter of agreement, dated February 3, 1993, to cap its 1993 earnings at its maximum authorized ROE. Thus, there should be sufficient earnings in 1993 to write-off the $ 247,758 in depreciation net reserve deficiencies as identified above and on Attachment A. These reserve transfers impact no accounts which involve arrangements with other affiliated or non affiliated companies. However, in light of the possible impact on cost allocations and jurisdictional separations, the Company should make corresponding entries to the related depreciation expense accounts.

IV. CAPITAL RECOVERY SCHEDULES

While current Company plans do not call for any near-term retirement of central office equipment, there are plans to replace the remaining aerial and air core buried cables with filled metallic buried cable **[*4]** by year-end 1994. Maintenance has been the major contributing factor towards this replacement program. In accord with its planning, the Company has proposed recovery schedules addressing the associated unrecovered costs of this retiring equipment over the 1993 and 1994 time period. Upon review, we find this to be reasonable and acceptable. During the course of this study review, the Company found that the reported investment of $ 1,265 associated with telephone devices for the deaf, Account 2362.1, represented plant no longer in service that should have been previously retired. This retirement results in a slight negative reserve which shall be recovered during 1993.

V. DEPRECIATION RATES AND AMORTIZATION

The Company proposal is based on an estimated reserve position whereas we have chosen to employ the actual January 1, 1993, reserve balance. A brief discussion of salient matters is set forth below.

A. General Support Assets

The approved lives for these accounts simply reflect an update of activity since the last study. Net salvages for the buildings accounts and construction equipment represent no change from that currently prescribed. There is a minor difference, **[*5]** however, in the net salvage proposed by the Company and that which we approve for passenger cars. Typically, for these vehicles, net salvage across the State ranges from 10% to 20%. We can find no reason why similar activity should not be expected to be incurred from any passenger cars purchased by Indiantown. Our decision is to retain the currently prescribed net salvage factor of 10%. The net salvage factor proposed for Light Trucks is in line with the activity of the account and we find it to be acceptable.

B. Central Office Assets

We approve the Company's proposals regarding life and salvage factors for these accounts. The life factors reflect the prospective impacts of network upgrading throughout the State. The expected life of upgradeable digital switchers remains problematic. However, a blending of projections of upgrade retirements as projected by various sources comports with the Company's proposed remaining life indicating that about 30% of the current embedded investments will have been retired by about 2004.

The analog carrier account investment represents primarily analog subscriber carrier with just over 10% being private line special circuit **[*6]** equipment. According to the Company, much of this equipment serves only for emergency or short-term use. As digital loop carrier or concentrators are placed, analog loop treatment will not be required. The Company's proposal reflects an update of activity since the last study which we find to be acceptable. However, this account should be monitored for any significant developments affecting its life expectancy.

The make-up of the digital carrier account has changed since the last depreciation review following the retirement of analog trunk carrier equipment. About 75% of this account is now comprised of line concentrator equipment which is not expected to be impacted by the move to the synchronous optic network. For this reason, we find the Company's proposed remaining life to be acceptable.

While there is merit to the Company's service life and net salvage factors for the fiber optic carrier account, we find it more appropriate to retain a whole life rate at this time rather than moving to a remaining life rate as proposed by the Company. Considering the anticipated growth in investment, the age of the account will remain very young resulting in essentially no difference **[*7]** between the service life and remaining life. Since this equipment is not SONET compatible, the Company should monitor the status of this account for possible impacts from the deployment of SONET equipment.

At the time of the last study, even though the Stuart West remote terminal was expected to be replaced with a stand alone switch due to increased growth demands, no building in the area had yet begun. Given the present economy, the fact that growth has stalled, and that currently there are no specific plans regarding replacement, we find continuation of the currently prescribed factors to be acceptable.

C. Information Origination/Termination Assets

The Company's proposed remaining lives simply reflect an update of age since the last study review. Upon review, we find them to be reasonable and acceptable.

D. Cable and Wire Facilities

According to the Company, of the $ 26,922 remaining in the Poles account, $ 8,450 represents stub poles used as pedestal supports, which should be reclassified to the Buried Cable Account. We have calculated the associated reserve amount to be $ 6,020. The investment and reserve shown on Attachment B for this account are reflective **[*8]** of this reclassification.

The Company has proposed a negative 50% net salvage in the Poles account; however, upon review, we approve a negative 30% net salvage based on a review of historical salvage experience and taking into consideration the labor intensiveness of the account.

Current industry projections for metallic cables reflect the scenario of a general phase-out of interoffice facilities by about 2000; feeder cable between 2005 and 2012; distribution facilities a few years later. Our decision utilizes these projections with an understanding that the impact on the smaller companies will generally lag that experienced by the larger companies which serve the more metropolitan high-tech areas.

The buried account is currently the only fiber account with investment. The Company has proposed to move to a remaining life rate at this time. However, considering the expected near-term growth in investment, the age will remain relatively young resulting in essentially no difference between service life and remaining life. Therefore, we find it more appropriate to continue a whole life rate.

The remaining life for conduit is simply reflective of the activity during the past three **[*9]** years since the last study review. We approve the Company proposed rate.

VI. TAXES

As set forth above, we have approved revisions to Indiantown's depreciation rates and capital recovery schedules, to be effective January 1, 1993. Revising a utility's depreciation rates usually results in a change in its rate of ITC amortization and flowback of excess deferred income taxes.

Section 46(f)(6) of the Internal Revenue Code provides that the amortization of ITCs should be determined by the period of time used in computing depreciation expense for purposes of reflecting regulated operating results of the utility. Since we have approved a change in depreciation rates, it is also appropriate to change the amortization of ITCs.

Section 203(e) of the Tax Reform Act of 1986 prohibits rapid write-back of protected (depreciation related) deferred taxes. In addition, Rule *25-14.013, Florida Administrative Code*, prohibits, without good cause shown, excess deferred income taxes associated with temporary differences from being reversed any faster than allowed under Section 203(e). Therefore, both Section 203(e) **[*10]** and Rule 25-14.013, prohibit faster write-off of protected excess deferred taxes. Consequently, the flowback of excess deferred taxes must be adjusted in order to comply with both Section 203(e) and Rule 25-14.013.

The Company has submitted detailed workpapers quantifying the impact of the proposed depreciation rates on the amortization of ITCs and the flowback of excess deferred income taxes. We have reviewed the calculations and find them to be accurate. However, the amounts reflected on the workpapers will change based on the approved depreciation rates.

The current amortization of ITCs and the flowback of excess deferred income taxes shall be revised to reflect the approved depreciation rates and recovery schedules. The Company shall be required to file detailed calculations of the revised ITC amortization and flowback of excess deferred taxes at the time it files its surveillance report.

Therefore, it is

ORDERED by the Florida Public Service Commission that the Company's plans and activity indicates a need to revise depreciation rates and recovery schedules. It is further

ORDERED that the implementation date for the new rates and capital recovery schedules **[*11]** shall be January 1, 1993. It is further

ORDERED that the restated reserve is approved as shown on Attachment A of this Order. The Company shall record an additional $ 247,758, total company depreciation expense in 1993. It is further

ORDERED that capital recovery schedules are approved as set forth on attachment B of this Order. It is further

ORDERED that depreciation rates and recovery/amortization schedules are approved as set forth on Attachment B of this Order. It is further

ORDERED that the current amortization of ITCs and the flowback of excess deferred income taxes shall be revised to reflect the approved depreciation rates and recovery schedules. The Company also shall be required to file detailed calculations of the revised ITC amortization and flowback of excess deferred taxes at the same time that it files its surveillance report. It is further

ORDERED that this Docket shall be closed at the conclusion of the protest period set forth below, assuming no timely protest is received.

By ORDER of the Florida Public Service Commission this 25th day of October, 1993.

ATTACHMENT A

INDIANTOWN TELEPHONE SYSTEM, INC.

1992 STUDY

APPROVED RESERVE TRANSFERS **[*12]**

ACCOUNT	1-1-93 BOOK RESERVE ($)	RESERVE IMBALANCE ($)	APPROVED RESERVE ($)
CONSTRUCTION EQUIP.	11,405	2,737	8,668
AERIAL METALLIC CABLE	(29,536)	(37,040)	7,504
BURIED MET. CABLE-FILLED	1,151,056	(213,455)	1,364,511
NET		** (247,758)	

ATTACHMENT B

INDIANTOWN TELEPHONE SYSTEM, INC.

1992 STUDY

	COMMISSION APPROVED RATES			
ACCOUNT	AVERAGE REMAINING LIFE (YRS.)	NET SALVAGE (%)	1/1/93 BOOK RESERVE (%)	REMAINING LIFE RATE (%)
GENERAL SUPPORT ASSETS				
Motor Vehicles - Passenger Cars	8.0	10.0	0.00	* 11.3
Motor Vehicles - Light Trucks	4.4	15.0	34.77	11.4
Construction Equipment	4.5	10.0	** 65.25	5.5
Buildings - Office	21.0	10.0	35.01	2.6
Buildings - Single - Unit	18.6	0.0	26.66	3.9
Buildings - Plant	27.0	5.0	19.85	2.8
CENTRAL OFFICE ASSETS				
Digital Switching	10.3	0.0	29.58	6.8
Analog Carrier	3.1	0.0	92.96	2.3
Digital Carier	7.6	0.0	49.17	6.7
Fiber Optic Carrier	10.0	0.0	13.75	* 10.0
Stuart West (New Additions)	11.8	0.0	0.00	* 8.5

** The net deficiency is to be written off during 1993.

* Denotes Whole Life Rate

** Denotes Restated Reserve

	COMMISSION APPROVED RATES			
ACCOUNT	AVERAGE REMAINING LIFE (YRS.)	NET SALVAGE (%)	1/1/93 BOOK RESERVE (%)	REMAINING LIFE RATE (%)
INFORMATION ORIG/TERM ASSETS				
Paystations	6.3	0.0	38.18	9.8
Terminating Equipment	6.9	0.0	39.16	8.8
CABLE & WIRE FACILITIES				
Poles	11.1	(30.0)	71.24	5.3
Aerial Cable - Fiber	20.0	(15.0)	0.00	* 5.8
Undgd. Cable - Metallic	11.4	(5.0)	42.12	5.5
Undgd. Cable - Fiber	20.0	(5.0)	0.00	* 5.3
Buried Cable - Metallic - Filled	11.0	(5.0)	34.53	6.4
Buried Cable - Fiber	20.0	(5.0)	7.16	* 5.3
Conduit	44.0	(5.0)	12.33	2.1
AMORTIZATION				
Other Work Equipment				7 Year Amortization
Furniture				10 Year Amortization
Office Support Equipment				7 Year Amortization
Company Communications				5 Year Amortization
General Purpose Computers				5 Year Amortization

[*13]

APPROVED RECOVERY SCHEDULES

ACCOUNT	1-1-93 Investment ($)	1-1-93 Reserve ($)	Period of Recovery	Annual Expenses ($)
Devices for the Deaf	0	(7)	1 Year	7
Aerial Metallic Cable	7,386	** 7,504	2 Year	990
Air Core Metallic Buried Cable	277,673	215,460	2 Year	31,107
Recovery Sch. Total	285,059	222,957		32,104

** Denotes Restated Reserve

End of Document

1994 Fla. PUC LEXIS 1219

Florida Public Service Commission

September 30, 1994

DOCKET NO. 931231-EI; ORDER NO. PSC-94-1199-FOF-EI, 94 FPSC 9:479

FL Public Service Commission Decisions

Reporter
1994 Fla. PUC LEXIS 1219 *

In Re: Request for change in Depreciation Rates by Florida Power and Light Company

Core Terms

plant, accessory, electric, boiler, depreciate, amortize, cost, dismantlement, unrecovered, has, revise, defer, reallocate, salvage, holder, fuel, abatement, asbestos, overhaul, surplus, mover, turkey, port, underground, accumulate, flowback, reactor, inject, steam, transmission

Panel: ; The following Commissioners participated in the disposition of this matter: J. TERRY DEASON, Chairman, SUSAN F. CLARK, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

Opinion

80 NOTICE OF PROPOSED AGENCY ACTION ORDER ESTABLISHING DEPRECIATION RATES, RECOVERY SCHEDULES, REVISING AMORTIZATION OF INVESTMENT TAX CREDITS AND DEFERRING DECISION ON AMORTIZATION OF NON-LIFE RELATED COSTS

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

Case Background

Rule 25-6.0436 (8)(a), Florida Administrative Code, requires each electric utility to file a study for each category of depreciable property for Commission review at least once every four years. In 1991 Florida Power and Light Company (FPL) filed site-specific depreciation studies for its Martin and Turkey Point (fossil) generating stations (Docket No. 900794-EI) and Putnam and St. Johns River Power Park facilities **[*2]** (Docket No. 901001-EI). FPL filed its regular quadrennial comprehensive depreciation study early in 1991 (Docket No. 910081-EI).

By Order No. PSC-92-1303-FOF-EI issued on November 12, 1992, in Docket Nos. 900794-EI, 901001-EI and 910081-EI, the Commission authorized continued use of the preliminary rates approved in Order No. 24161 for FPL for 1991 and 1992. This action was based on concerns about the catastrophic effects of Hurricane Andrew on FPL's operations and plant. FPL was directed to file an updated comprehensive depreciation study by June 1993 with an effective date of January 1, 1993.

ATTACHMENT B

Subsequently, as reflected in Order No. PSC-93-0211-FOF-EI, FPL agreed to file a comprehensive study covering production, transmission, distribution and general plant in December, 1993 with a January 1, 1994 implementation date. The same Order provides that dismantlement studies and decommissioning studies will be filed in December, 1994 with a January 1, 1995 implementation date. This schedule facilitates a comprehensive review of depreciation parameters for all categories of plant at the same time, while allowing the review of extraordinary removal costs (fossil dismantlement and nuclear **[*3]** decommissioning) at a later time.

On December 20, 1993, FPL filed its depreciation study in the current docket covering production, transmission, distribution and general plant, as required by Order No. PSC-93-0211-FOF-EI. At the February 15, 1994 Agenda, the Commission approved FPL's request to implement its proposed depreciation rates and recovery schedule on a preliminary basis effective, January 1, 1994 (Order No. PSC-94-0253-FOF-EI). This Order establishes the appropriate final depreciation rates and recovery schedules to be implemented by FPL. Commission action concerning certain accounting issues raised during the review of the study has been addressed in Order No. PSC-94-1173-FOF-EI, issued September 26, 1994.

81 The purpose of this depreciation study is to determine and provide for the appropriate depreciation rates and recovery schedules for FPL's production, transmission, distribution and general plant. We have completed our analysis and review of the Company's depreciation study and are ordering revisions to the approved preliminary rates.

The only issue not being addressed at this time is what the appropriate amortization period should be for the remaining unrecovered **[*4]** costs associated with the major overhaul and asbestos abatement projects completed during the 1988 - 1993 period. There is no disagreement between FPL and the Commission Staff that these costs are non-life related. Therefore, amortization should be afforded as fast as economically practicable.

Staff and FPL do disagree as to what is the economically feasible amortization period. FPL has proposed a 4 year amortization period. Staff believes that more accurate information concerning the 1994 earnings position should be available before a determination of the most appropriate amortization period is made. We agree with Staff. The October 1994 surveillance report will be submitted on or before December 15, 1994. For this reason, we defer the decision regarding the amortization period for the non-life related unrecovered costs until the January 20, 1995 Agenda.

Accumulated Reserve Adjustments Attributable to Interest Synchronization (Job Development Investment Credit - JDIC)

By Order No. 16257, the Commission decided that depreciation reserve adjustments should be used to offset revenue requirements associated with the interest synchronization of investment tax credits until **[*5]** base rates were changed. In compliance with that order, FPL has been accumulating reserve adjustments attributable to JDIC to a bottom line unclassified depreciation reserve account. The accumulated amounts for the period 1990 - 1993 total $ 8,326,512 on a System basis. These accumulated amounts are now subject to reallocation to specific accounts.

FPL has proposed that these amounts be applied as a contribution to the Storm Damage reserve. An alternative treatment is to apply these JDIC monies to reduce the unrecovered costs remaining from the pre-1994 major overhaul and asbestos abatement projects. With the Storm Damage docket currently pending (Docket No. 930405-EI), and a review of MMFRs due in 1995, we believe that these JDIC monies should continue to accumulate in a bottom line reserve account with disposition to be determined at a later date. Therefore we find that the $ 8.3 million, System basis, attributable to JDIC (Order No. 16257) accumulated as of January 1, 1994 as well as the on-going monthly adjustments of $ 171,785 shall remain in an unclassified depreciation reserve account.

Reserve Reallocations

One aspect of a depreciation study is the review of the reserve **[*6]** status of all production sites and all transmission, distribution and general plant accounts to determine the need for corrective reserve transfers. Due

to the effect reserve transfers may have on jurisdictional separations, purchase power agreements, or other lease arrangements, our approach to reserve reallocations is that they should, ideally, be made between accounts of 82
a given unit or function. The allocations discussed and approved below (shown in detail on Attachment C) address major imbalances generally brought about by transfers associated with the unitization of certain production plants and previously unanticipated final dismantlement costs of certain units.

The reserve reallocations approved for Ft. Myers Common and Port Everglades are needed to correct major imbalances brought about by the unitization of these plants.

Based on the recommended life and salvage components for the Riviera production plant, there is an apparent calculated reserve surplus for Unit 3, Account 311, in the amount of $ 401,515. Part of this surplus is due to a JDIC reallocation of $ 318,206 made in 1987. Further, Riviera Unit 4, Account 311, has a perceived reserve surplus of $ 293,072 **[*7]** of which $ 272,718 is also attributed to a JDIC allocation made in 1987. We find that these JDIC amounts shall be reallocated to help alleviate the negative reserve balances at Riviera Unit 1 and Cutler Unit 4 that are attributed to dismantlement activities that were not previously anticipated. This will still leave a minor negative dismantlement reserve balance of $ 729 at the Cutler unit which shall be amortized during 1994. There remains an additional $ 83,309 surplus at Riviera Unit 3, Account 311. Because a book reserve in excess of 100% still results without further corrective action, we find that this surplus shall be reallocated to help offset the remaining unrecovered costs associated with the pre-1994 major overhaul and asbestos abatement projects.

Another major imbalance is noted for Ft. Myers Unit 1, Account 311. This account reportedly has a January 1, 1994 book reserve over 150% with a calculated reserve surplus of $ 552,618. In fact, the Ft. Myers site has an overall perceived surplus of about $ 3.2 million. As discussed previously, due to concerns reserve transfers may have on jurisdictional separations, purchase power agreements, or other lease arrangements, **[*8]** reallocations are ideally made between accounts of a given unit. In this case, however, Unit 1 has an overall perceived surplus. For this reason, we find that this surplus shall be transferred to also help offset the remaining unrecovered costs associated with the pre-1994 major overhaul and asbestos abatement projects.

As part of the review of the 1993 activity, several accounts were found to have negative reserve balances resulting from dismantlement activities that were charged to the account reserves, rather than to the associated dismantlement reserve. Cutler Common, Accounts 312 and 314, are examples. Both these accounts show negative reserve balances as of January 1, 1994 in the amounts of $ 122,851 and $ 57,283, respectively. Purportedly, these negative reserves are the result of cost of removal charges associated with the dismantlement of Cutler Unit 4. These removal costs were charged to each account's reserve rather than correctly being charged to the appropriate dismantlement reserve. For this reason, we find that the removal costs of $ 176,680 and $ 66,365, respectively, shall be transferred out of each account's reserve and charged to the dismantlement reserve. **[*9]**

According to FPL, none of the sites/accounts for which reserve reallocations have been approved are affected by any lease arrangements or purchase power agreements. However, in light of the possible impact of reserve transfers on cost allocations and jurisdictional separations, we find that the Company shall make corresponding entries to the related depreciation expense accounts.

83 Appropriate Depreciation Rates and Recovery Schedules

Attachment A shows the approved life and salvage parameters and the resulting depreciation rates. Recommended recovery schedules are shown on Attachment B. The resulting annual expense of about $ 533 million, based on actual January 1, 1994 investments, represents an increase of about $ 11.7 million as compared to the preliminary rates approved by Order No. PSC-94-0253-FOF-EI. Expenses for 1994 shall be trued-up accordingly.

The most significant changes in expenses are seen in the area of production plants and recovery schedules.

Production Plant

FPL's mechanized property record system affords it the ability to provide in-depth stratified information for the assets in an account at a specific unit. A generating station, or a generating **[*10]** unit, can be looked at as a box - a box containing an assortment of various types of assets which can be expected to experience varied service lives. The historic approach was to arrive at the pattern of interim retirement and life expectancy of the box without identifying the contents or quantifying the varying life characteristics of the contained assets. Stratification is the determination that this account at this unit has so many dollars of pumps, of piping, of rotors, or structures, etc., with each of these strata expected to have a certain service life. The life of the account can then be arrived at by compositing the expectations of the various strata - and with substantially more assurance of accuracy than guessing at the service life of the box with its unidentified contents. While there are some desirable changes that should be made to this study, it is nevertheless quite advanced and very well conceived.

The Company projections of lives for the various strata, and of expected interim net salvage values are reasonable. While unitization is not yet complete for all production plants, it is our understanding that this process will be completed by the time of the next **[*11]** overall review. For production plants that have not completed unitization, the Company's development of life is still based on a methodology using multiple iterations for sub-strata detail to determine the average service life of a strata. This approach is fundamentally flawed since it develops life characteristics based on the expected lives of embedded investments as well as future replacements. We are encouraged that the Company has completed unitization for most of its production facilities and will utilize a single iteration methodology in the next filing for all plants.

The primary difference between the interim approved life components and resultant rates and what is approved in this Order is associated with the St. Lucie and Turkey Point nuclear plants. In the original study, the average ages and remaining lives for each strata were as of January 1, 1991 and therefore, required updating to January 1, 1994. This Order reflects the updated average ages and remaining lives.

Recovery Schedules

There are five recovery schedules approved as shown on Attachment B. These schedules address the most current Company plans regarding the near term retirement of the 84 St. Lucie **[*12]** steam generators, the recovery of residual unrecovered costs associated with dismantlement activities at Cutler Unit 4 and Sanford Unit 1, the recovery of silicone injection costs and the unrecovered costs associated with asbestos abatement and major overhaul projects.

The continued corrosion of the steam generator tubes at St. Lucie Unit 1 has resulted in 12% and 7% of the tubes at each of the steam generators being plugged. For this reason, current plans call for the replacement of the two steam generators in 1998. We find that FPL's proposed recovery schedule for the unrecovered costs associated with this replacement is reasonable and therefore, acceptable. The recovery period is designed to match the remaining period the generators will be in service.

A recovery schedule is also approved for Account 367.7, Underground Conductors and Devices-Direct Buried. FPL's cable injection program began in 1989 and was guaranteed for 10 years. Since the last depreciation review, the process has been modified and is now guaranteed for 20 years. In view of this, we approve the removal of the investment and reserve associated with the 10 year guaranteed cable injection investment and **[*13]** the amortization of the unrecovered cost over the remaining average guarantee period of eight years (based on the investment's average age of approximately 2 years). It is further approved that, for 1994 and subsequent years, the 10 year guaranteed cable injection costs shall be amortized over 10 years. The 20 year guaranteed cable injection shall be depreciated over the life of the cable.

In addition, there are two production units which are no longer in service but have existing residual negative reserve amounts resulting from unforeseen dismantlement costs. These unrecovered costs are non-life related in that they relate to plant no longer serving the public. Accordingly, recovery should be afforded as soon as economically practicable. Therefore, we approve a one year amortization period.

The Company has also identified major overhaul and asbestos abatement projects currently planned for specified units for the period January 1, 1994 through December 31, 1997. The associated unrecovered investments are estimated to be $ 3,579,592. This amount should be recovered over a period matching the remaining period in service. A four year period is therefore approved.

Revision **[*14]** to Current Investment Tax Credit (ITC) Amortization and the Flowback of Excess Deferred Income Taxes

In this Order, we have approved revisions to FPL's depreciation rates and recovery schedules. Revising a utility's depreciation rates typically results in a change in its rate of ITC amortization and a change in its flowback of excess deferred taxes.

FPL is treated under Section 46(f)(2) of the Internal Revenue Code (IRC), which results in weighted cost ITCs in its capital structure and above-the-line ITC amortization in its income tax expense. Section 46(f)(6) of the IRC states that the amortization of ITCs should be determined by the period used in computing depreciation expense for purposes of reflecting regulated operating results of the utility. Rule 25-14.008(3)(b)(3), Florida Administrative Code, states that where an election was made under Section 46(f)(2) of the Internal Revenue Code, reductions to cost of service are made based on ratable allocations 85 of the credit in proportion to the regulated depreciation expense. **[*15]** Consequently, a change in depreciation rates usually results in a change in the amortization of ITCs.

Regarding the flowback of excess deferred taxes, Section 203(e) of the Tax Reform. Act of 1986 (TRA) prohibits rapid write-back of excess protected (depreciation related) deferred taxes. Also, Rule *25-14.013, Florida Administrative Code*, prohibits (without good cause shown) excess deferred income taxes from being reversed any faster than allowed under either the average rate assumption method of Section 203(e) of the TRA or *Revenue Procedure 88-12*, whichever is applicable. Consequently, the flowback of excess deferred taxes should be altered to comply with the TRA and Rule *25-14.013, Florida Administrative Code*.

FPL shall file a report with detailed calculations of the adjusting entries, revised ITC amortization and revised flowback of excess deferred taxes at the same time it files its December 1994 Earnings Surveillance Report.

Implementation Date for Approved Rates and Recovery Schedules

Company data and related calculations are based on a January 1, 1994 **[*16]** date. This is the earliest practicable date for utilizing the revised rates and recovery schedules. Therefore, we approve the Company's proposed January 1, 1994 date for implementation of the new depreciation rates and recovery schedules.

It is therefore,

ORDERED that the decision regarding the amortization period for the non-life related unrecovered costs shall be deferred until the January 20, 1995 Agenda. It is further

ORDERED that the remaining life and salvage parameters, and the resulting depreciation rates discussed in this Order and detailed in Attachment A are approved. It is further

ORDERED that the recovery schedules discussed in this Order and detailed in Attachment B are approved. It is further

ORDERED that the reserve reallocations discussed in this Order and detailed in Attachment C are approved. It is further

ORDERED that the Company's proposed January 1, 1994 date of implementation for the new depreciation rates and recovery schedules is approved. It is further

ORDERED that the $ 8.3 million, system basis, attributable to JDIC (Order No. 16257) accumulated as of January 1, 1994 as well as the on-going monthly adjustments of $ 171,785 shall remain in **[*17]** an unclassified depreciation reserve account. It is further

ORDERED that Florida Power and Light Comapny shall revise its ITC amortization and the flowback of excess deferred income taxes to reflect the approved depreciation rates and recovery schedules. It is further

ORDERED that Florida Power and Light Company shall file a report with detailed calculations of the adjusting entries, revised ITC amortization and revised flowback of excess deferred taxes at the same time it files its December 1994 Earnings Surveillance Report. It is further

86 ORDERED this docket shall remain open pending a determination of the appropriate economically practicable period to amortize the remaining costs associated with major overhaul and asbestos abatement projects completed during the 1988 - 1993 period.

By ORDER of the Florida Public Service Commission, this 30th day of September, 1994.

87 FLORIDA POWER AND LIGHT COMPANY

1993 DEPRECIATION STUDY

COMMISSION APPROVED RATES

	AVERAGE		**ACTUAL**	**REMAINING**
	REMAINING	**NET**	**1-1-94**	**LIFE**
ACCOUNT	**LIFE**	**SALVAGE**	**RESERVE**	**RATE**
ACCOUNT				
STEAM PRODUCTION				
Cape Canaveral-Common				
311 Structures and Improvements	16.1	(5.0)	* 42.6	3.9
312 Boiler Plant Equip.	21.0	(13.0)	* 22.9	4.3
314 Turbogenerator Units	16.4	(4.0)	64.7	2.4
315 Accessory Electric Equip.	19.0	(3.0)	79.6	1.2
316 Misc. Power Plant Equip.	13.8	(1.0)	43.3	4.2
Cape Canaveral-Unit 1				
311 Structures and Improvements	17.9	(5.0)	65.2	2.2
312 Boiler Plant Equip.	20.0	(13.0)	* 18.3	4.7
314 Turbogenerator Units	20.0	(4.0)	* 46.8	2.9
315 Accessory Electric Equip.	17.9	(3.0	40.4	3.5
316 Misc. Power Plant Equip.	14.4	(1.0)	69.7	2.2
Cape Canaveral-Unit 2				
311 Structures and Improvements	15.0	(5.0)	59.4	3.0

* Denotes Restated Reserve

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
312 Boiler Plant Equip.	16.4	(13.0)	* 29.8	5.1
314 Turbogenerator Units	10.1	(4.0)	* 70.6	3.3
315 Accessory Electric Equip.	14.3	(3.0)	41.1	4.3
316 Misc. Power Plant Equip.	8.1	(1.0)	* 82.2	2.3
Cutler-Common				
311 Structures and Improvements	9.5	0.0	* 51.9	5.1
312 Boiler Plant Equip.	9.5	0.0	* 17.5	8.7
314 Turbogenerator Units	9.5	0.0	* 1.0	10.4
315 Accessory Electric Equip.	9.4	0.0	* 17.5	8.8
316 Misc. Power Plant Equip.	9.1	0.0	66.1	3.7
Cutler-Unit 5				
311 Structures and Improvements	9.2	0.0	70.7	3.2
312 Boiler Plant Equip.	8.2	0.0	* 63.8	4.4
314 Turbogenerator Units	9.5	0.0	52.0	5.1
315 Accessory Electric Equip.	9.4	0.0	* 35.3	6.9
316 Misc. Power Plant Equip.	8.4	0.0	52.7	5.6
Manatee-Unit 1				
311 Structures and Improvements	15.2	(5.0)	49.0	3.7
312 Boiler Plant Equip.	10.9	(13.0)	* 56.6	5.2
314 Turbogenerator Units	12.5	(4.0)	* 33.7	5.6
315 Accessory Electric Equip.	11.1	(3.0)	48.3	4.9
316 Misc. Power Plant Equip.	16.2	(1.0)	55.9	2.8
Manatee-Unit 2				
311 Structures and Improvements	15.6	(5.0)	46.0	3.8
312 Boiler Plant Equip.	11.3	(13.0)	54.2	5.2
314 Turbogenerator Units	13.1	(4.0)	* 33.2	5.4
315 Accessory Electric Equip.	11.8	(3.0)	43.8	5.0
316 Misc. Power Plant Equip.	16.8	(1.0)	49.4	3.1
Martin Pipeline				
312 Boiler Plant Equip.	10.6	(13.0)	2.9	10.4

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
Martin-Common				
311 Structures and Improvements	19.6	(5.0)	* 38.6	3.4
312 Boiler Plant Equip.	19.6	(13.0)	44.2	3.5
314 Turbogenerator Units	19.9	(4.0)	45.1	3.0
315 Accessory Electric Equip.	15.2	(3.0)	45.7	3.8
316 Misc. Power Plant Equip.	6.0	(1.0)	36.2	10.8
Martin-Unit 1				
311 Structures and Improvements	20.0	(5.0)	44.6	3.0
312 Boiler Plant Equip.	14.5	(13.0)	44.4	4.7
314 Turbogenerator Units	18.9	(4.0)	* 28.2	4.0
315 Accessory Electric Equip.	16.4	(3.0)	35.3	4.1
316 Misc. Power Plant Equip.	20.0	(1.0)	44.9	2.8
Martin-Unit 2				
311 Structures and Improvements	20.0	(5.0)	33.5	3.6
312 Boiler Plant Equip.	14.9	(13.0)	41.0	4.8
314 Turbogenerator Units	17.9	(4.0)	* 47.2	3.2
315 Accessory Electric Equip.	16.9	(3.0)	35.1	4.0
316 Misc. Power Plant Equip.	21.0	(1.0)	34.5	3.2
Cutler-Unit 6				
311 Structures and Improvements	8.6	0.0	88.3	1.4
312 Boiler Plant Equip.	8.3	0.0	* 62.1	4.6
314 Turbogenerator Units	6.0	0.0	80.5	3.2
315 Accessory Electric Equip.	9.4	0.0	57.3	4.5
316 Misc. Power Plant Equip.	9.3	0.0	93.9	0.7
Ft. Myers-Common				
311 Structures and Improvements	16.8	(5.0)	* 49.6	3.3
312 Boiler Plant Equip.	18.5	(13.0)	46.6	3.6
314 Turbogenerator Units	17.1	(4.0)	* 35.6	4.0
315 Accessory Electric Equip.	14.8	(3.0)	* 40.7	4.2
316 Misc. Power Plant Equip.	14.6	(1.0)	59.6	2.8

COMMISSION APPROVED RATES

	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE
ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
Ft. Myers-Unit 1				
311 Structures and Improvements	9.3	(5.0)	* 78.0	2.9
312 Boiler Plant Equip.	9.1	(13.0)	* 84.5	3.1
314 Turbogenerator Units	9.5	(4.0)	90.6	1.4
315 Accessory Electric Equip.	9.2	(3.0)	71.9	3.4
316 Misc. Power Plant Equip.	7.8	(0.7)	97.7	0.4
Ft. Myers-Unit 2				
311 Structures and Improvements	15.0	(5.0)	75.8	1.9
312 Boiler Plant Equip.	16.1	(13.0)	* 60.2	3.3
314 Turbogenerator Units	9.5	(4.0)	* 71.1	3.5
315 Accessory Electric Equip.	13.7	(3.0)	54.0	3.6
316 Misc. Power Plant Equip.	8.0	(1.0)	54.6	5.8
Manatee-Common				
311 Structures and Improvements	17.2	(5.0)	* 47.0	3.4
312 Boiler Plant Equip.	7.0	(13.0)	41.8	10.2
314 Turbogenerator Units	17.4	(4.0)	* 49.1	3.2
315 Accessory Electric Equip.	13.7	(3.0)	49.5	3.9
316 Misc. Power Plant Equip.	9.6	(1.0)	42.7	6.1
Port Everglades-Common				
311 Structures and Improvements	13.1	(5.0)	* 41.2	4.9
312 Boiler Plant Equip.	15.5	(13.0)	52.0	3.9
314 Turbogenerator Units	15.5	(4.0)	49.3	3.5
315 Accessory Electric Equip.	14.4	(3.0)	34.4	4.8
316 Misc. Power Plant Equip.	12.7	(1.0)	39.8	4.8
Port Everglades-Unit 1				
311 Structures and Improvements	9.3	(5.0)	* 79.9	2.7
312 Boiler Plant Equip.	5.9	(13.0)	* 68.9	7.5
314 Turbogenerator Units	9.2	(4.0)	* 70.9	3.6
315 Accessory Electric Equip.	8.3	(3.0)	79.7	2.8
316 Misc. Power Plant Equip.	8.7	(1.0)	83.7	2.0

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
Port Everglades-Unit 2				
311 Structures and Improvements	9.4	(5.0)	* 75.5	3.1
312 Boiler Plant Equip.	7.2	(13.0)	* 79.2	4.7
314 Turbogenerator Units	9.1	(4.0)	80.6	2.6
315 Accessory Electric Equip.	7.8	(3.0)	71.1	4.1
316 Misc. Power Plant Equip.	7.4	(1.0)	62.7	5.2
Port Everglades-Unit 3				
311 Structures and Improvements	13.3	(5.0)	63.5	3.1
312 Boiler Plant Equip.	14.5	(13.0)	* 50.4	4.3
314 Turbogenerator Units	14.8	(4.0)	* 59.9	3.0
315 Accessory Electric Equip.	15.0	(3.0)	30.8	4.8
316 Misc. Power Plant Equip.	11.3	(1.0)	30.2	6.3
Port Everglades-Unit 4				
311 Structures and Improvements	13.9	(5.0)	71.3	2.4
312 Boiler Plant Equip.	14.7	(13.0)	* 31.5	5.5
314 Turbogenerator Units	14.1	(4.0)	* 71.5	2.3
315 Accessory Electric Equip.	15.1	(3.0)	28.0	5.0
316 Misc. Power Plant Equip.	7.2	(1.0)	56.4	6.2
Riviera -- Common				
311 Structures and Improvements	17.3	(5.0)	* 52.8	3.0
312 Boiler Plant Equip.	20.0	(13.0)	* 25.8	4.4
314 Turbogenerator Units	18.9	(4.0)	55.5	2.6
315 Accessory Electric Equip.	13.7	(3.0)	46.6	4.1
316 Misc. Power Plant Equip.	11.0	(1.0)	68.6	2.9
Riviera -- Unit 3				
311 Structures and Improvements	17.7	(5.0)	* 67.8	2.1
312 Boiler Plant Equip.	13.2	(13.0)	* 63.1	3.8
314 Turbogenerator Units	18.2	(4.0)	* 78.6	1.4
315 Accessory Electric Equip.	17.2	(3.0)	50.4	3.1
316 Misc. Power Plant Equip.	19.5	(1.0)	46.7	2.8
Riviera -- Unit 4				

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
311 Structures and Improvements	18.2	(5.0)	* 84.8	1.1
312 Boiler Plant Equip.	13.2	(13.0)	* 57.3	4.2
314 Turbogenerator Units	19.9	(4.0)	* 46.8	2.9
315 Accessory Electric Equip.	17.6	(3.0)	41.8	3.5
316 Misc. Power Plant Equip.	21.0	(1.0)	32.7	3.3
Sanford -- Common				
311 Structures and Improvements	16.0	(5.0)	* 47.3	3.6
312 Boiler Plant Equip.	18.9	(13.0)	52.2	3.2
314 Turbogenerator Units	18.4	(4.0)	63.7	2.2
315 Accessory Electric Equip.	17.7	(3.0)	59.7	2.4
316 Misc. Power Plant Equip.	9.6	(1.0)	47.6	5.6
Sanford -- Unit 3				
311 Structures and Improvements	9.4	(5.0)	87.8	1.8
312 Boiler Plant Equip.	9.4	(13.0)	* 91.0	2.3
314 Turbogenerator Units	9.1	(4.0)	* 85.4	2.0
315 Accessory Electric Equip.	8.7	(3.0)	84.8	2.1
316 Misc. Power Plant Equip.	9.5	(1.0)	75.6	2.7
Sanford -- Unit 4				
311 Structures and Improvements	17.9	(5.0)	57.3	2.7
312 Boiler Plant Equip.	16.9	(13.0)	* 59.8	3.1
314 Turbogenerator Units	8.5	(4.0)	* 58.1	5.4
315 Accessory Electric Equip.	12.1	(3.0)	60.0	3.6
316 Misc. Power Plant Equip.	13.8	(1.0)	63.8	2.7
Sanford -- Unit 5				
311 Structures and Improvements	17.8	(5.0)	49.2	3.1
312 Boiler Plant Equip.	17.4	(13.0)	* 63.5	2.8
314 Turbogenerator Units	10.7	(4.0)	* 48.8	5.2
315 Accessory Electric Equip.	12.6	(3.0)	60.0	3.4
316 Misc. Power Plant Equip.	13.9	(1.0)	60.1	2.9
Scherer Site Common				

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
311 Structures and Improvements	32.0	(5.0)	17.0	2.8
312 Boiler Plant Equip.	29.0	(20.0)	21.4	3.4
314 Turbogenerator Units	25.0	(4.0)	18.6	3.4
315 Accessory Electric Equip.	25.0	(3.0)	19.3	3.3
316 Misc. Power Plant Equip.	6.0	(1.0)	43.8	9.5
Scherer Units 3 & 4 Common				
311 Structures and Improvements	25.0	(5.0)	18.7	3.5
312 Boiler Plant Equip.	33.0	(20.0)	17.3	3.1
314 Turbogenerator Units	24.0	(4.0)	19.2	3.5
315 Accessory Electric Equip.	23.0	(3.0)	20.3	3.6
Scherer Unit 4				
311 Structures and Improvements	31.0	(5.0)	10.9	3.0
312 Boiler Plant Equip.	27.0	(20.0)	13.9	3.9
314 Turbogenerator Units	25.0	(4.0)	13.6	3.6
315 Accessory Electric Equip.	23.0	(3.0)	14.0	3.9
316 Misc. Power Plant Equip.	15.8	(1.0)	17.7	5.3
Turkey Point -- Common				
311 Structures and Improvements	19.3	(5.0)	* 51.6	2.8
312 Boiler Plant Equip.	19.2	(13.0)	36.8	4.0
314 Turbogenerator Units	17.6	(4.0)	54.7	2.8
315 Accessory Electric Equip.	16.1	(3.0)	* 41.1	3.8
316 Misc. Power Plant Equip.	14.6	(1.0)	45.3	3.8
Turkey Point -- Unit 1				
311 Structures and Improvements	16.3	(5.0)	* 24.0	5.0
312 Boiler Plant Equip.	18.1	(13.0)	* 29.7	4.6
314 Turbogenerator Units	17.8	(4.0)	* 36.9	3.8
315 Accessory Electric Equip.	15.3	(3.0)	55.8	3.1
316 Misc. Power Plant Equip.	14.8	(1.0)	69.8	2.1
Turkey Point -- Unit 2				
311 Structures and Improvements	19.0	(5.0)	29.3	4.0

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
312 Boiler Plant Equip.	15.3	(20.0)	* 52.0	4.4
314 Turbogenerator Units	17.7	(4.0)	* 61.2	2.4
315 Accessory Electric Equip.	16.1	(3.0)	52.7	3.1
316 Misc. Power Plant Equip.	16.9	(1.0)	64.2	2.2
St. Johns Rvr Power Park -- Common				
311 Structures and Improvements	27.0	(5.0)	47.6	2.1
312 Boiler Plant Equip.	28.0	(20.0)	38.8	2.9
314 Turbogenerator Units	28.0	(4.0)	15.9	3.1
315 Accessory Electric Equip.	25.0	(3.0)	39.5	2.5
316 Misc. Power Plant Equip.	8.9	(1.0)	73.6	3.1
St. Johns Rvr Power Park -- Unit 1				
311 Structures and Improvements	28.0	(4.7)	27.8	2.7
312 Boiler Plant Equip.	23.0	(20.0)	29.4	3.9
314 Turbogenerator Units	22.0	(4.0)	23.7	3.7
315 Accessory Electric Equip.	21.0	(2.7)	24.6	3.7
316 Misc. Power Plant Equip.	19.9	(1.0)	23.8	3.9
St. Johns Rvr Power Park -- Unit 2				
311 Structures and Improvements	29.0	(4.7)	21.9	2.9
312 Boiler Plant Equip.	24.0	(20.0)	23.4	4.0
314 Turbogenerator Units	23.0	(4.0)	18.4	3.7
315 Accessory Electric Equip.	22.0	(2.7)	19.7	3.8
316 Misc. Power Plant Equip.	21.0	(1.0)	14.5	4.1
St. Johns Rvr Power Park -- Coal/Limestone				
311 Structures and Improvements	30.0	(5.0)	9.5	3.2
312.15 Coal Cars	8.5	(20.0)	40.6	9.3
312 Boiler Plant	24.0	(20.0)	42.5	3.2
315 Accessory Electric Equip.	19.7	(3.0)	14.5	4.5
316 Misc. Power Plant Equip.	22.0	(1.0)	28.9	3.3
St. Johns Rvr Power Park -- Gypsum/Ash				

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
311 Structures	31.0	(5.0)	47.4	1.9
312 Boiler Plant	16.7	(20.0)	32.3	5.3
315 Accessory Electric Equip.	17.5	(3.0)	24.4	4.5
316 Misc. Power Plant Equip.	24.0	(1.0)	29.9	3.0

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95 FLORIDA POWER AND LIGHT COMPANY

1993 DEPRECIATION STUDY

COMMISSION APPROVED RATES

ACCOUNT	AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
OTHER PRODUCTION				
Ft. Lauderdale -- Common (Repowered)				
341 Structures and Improvements	24.0	(2.0)	* .09	4.2
342 Fuel Holders, Producers & Accessories	17.8	(2.0)	8.7	5.2
343 Prime Movers	27.0	(2.0)	3.7	3.6
344 Generators	16.5	(2.0)	34.9	4.1
345 Accessory Electric Equipment	28.0	(1.0)	8.4	3.3
346 Misc. Power Plant Equipment	10.5	(1.0)	32.0	6.6
Ft. Lauderdale -- Unit 4 (Repowered)				
341 Structures and Improvements	27.0	(2.0)	2.0	3.7
342 Fuel Holders, Producers & Accessories	24.0	(2.0)	1.2	4.2
343 Prime Movers	28.0	(2.0)	* 2.3	3.6
344 Generators	16.4	(2.0)	* 7.9	5.7
345 Accessory Electric Equipment	28.0	(1.0)	* 4.8	3.4

* Denotes Restated Reserve

	COMMISSION APPROVED RATES			
	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE
ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
346 Misc. Power Plant Equipment	16.3	(1.0)	* 6.3	5.8
Ft. Lauderdale -- Unit 5 (Repowered)				
341 Structures and Improvements	28.0	(2.0)	* 7.4	3.4
342 Fuel Holders, Producers & Accessories	23.0	(2.0)	1.9	4.4
343 Prime Movers	28.0	(2.0)	* 4.8	3.5
344 Generators	16.1	(2.0)	* 6.3	5.9
345 Accessory Electric Equipment	28.0	(1.0)	* 10.0	3.3
346 Misc. Power Plant Equipment	15.9	(1.0)	* 2.3	6.2
Ft. Myers -- Gas Turbines				
341 Structures	9.5	(2.0)	86.1	1.7
342 Fuel Holders	9.5	(2.0)	89.1	1.4
343 Prime Movers	9.5	(2.0)	82.4	2.1
344 Generator	9.5	(2.0)	78.2	2.5
345 Accessory Electric Equip.	9.5	(2.3)	81.4	2.2
346 Misc. Power Plant Equip.	9.5	(6.4)	59.9	4.9
Ft. Lauderdale-Gas Turbines				
341 Structures	9.5	(2.0)	74.2	2.9
342 Fuel Holders	9.5	(2.0)	86.9	1.6
343 Prime Movers	9.5	(2.0)	81.4	2.2
344 Generator	9.5	(2.0)	93.1	0.9
345 Accessory Electric Equip.	9.5	(1.0)	84.4	1.7
346 Misc. Power Plant Equip.	9.5	(1.0)	90.7	1.1
Port Everglades -- Gas Turbines				
341 Structures	9.5	(2.0)	81.7	2.1
342 Fuel Holders	9.4	(2.0)	92.2	1.0
343 Prime Movers	9.5	(2.0)	94.1	0.8
344 Generator	9.5	(1.0)	93.5	0.8
345 Accessory Electric Equip.	6.9	(1.0)	97.4	0.5
346 Misc. Power Plant Equip.	8.5	(1.0)	81.9	2.2

	COMMISSION APPROVED RATES			
	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE
ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
Martin Pipeline				
342 Fuel Holders	10.6	(2.0)	3.0	9.4
Putnam -- Common				
341 Structures	16.1	(2.0)	55.6	2.9
342 Fuel Holders	18.5	(2.0)	17.9	4.5
343 Prime Movers	16.6	(2.0)	19.2	5.0
344 Generator	14.5	(2.0)	34.8	4.6
345 Accessory Electric Equip.	13.1	(1.0)	41.1	4.6
346 Misc. Power Plant Equip.	12.8	(1.0)	49.0	4.1
Putnam -- Unit 1				
341 Structures	15.5	(2.0)	54.4	3.1
342 Fuel Holders	15.6	(2.0)	55.9	3.0
343 Prime Movers	15.6	(2.0)	* 25.1	4.9
344 Generator	13.0	(2.0)	60.0	3.2
345 Accessory Electric Equip.	14.4	(1.0)	54.0	3.3
Putnam -- Unit 2				
341 Structures	15.3	(2.0)	57.4	2.9
342 Fuel Holders	15.3	(2.0)	51.7	3.3
343 Prime Movers	15.6	(2.0)	* 27.3	4.8
344 Generator	12.4	(2.0)	63.6	3.1
345 Accessory Electric Equip.	14.0	(1.0)	58.1	3.1

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1993 DEPRECIATION STUDY

	COMMISSION APPROVED RATES			
	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE

ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
NUCLEAR PRODUCTION				
St. Lucie -- Common				
321 Structures & Improvements	24.0	(2.0)	34.7	2.8
322 Reactor Plant Equipment	28.0	(12.0)	15.1	3.5
323 Turbogenerator Units	23.0	(1.0)	11.4	3.9
324 Accessory Electric Equipment	26.0	0.0	19.4	3.1
325 Misc. Power Plant Equipment	23.0	0.0	25.1	3.3
St. Lucie -- Unit 1				
321 Structures & Improvements	19.7	(2.0)	40.8	3.1
322 Reactor Plant Equipment	18.4	(13.0)	* 31.4	4.4
323 Turbogenerator Units	18.6	(1.0)	37.5	3.4
324 Accessory Electric Equipment	21.0	0.0	35.2	3.1
325 Misc. Power Plant Equipment	22.0	0.0	37.9	2.8
St. Lucie -- Unit 2				
321 Structures & Improvements	21.0	(2.0)	27.3	3.6
322 Reactor Plant Equipment	24.0	(12.0)	29.0	3.5
323 Turbogenerator Units	26.0	(1.0)	22.4	3.0
324 Accessory Electric Equipment	28.0	0.0	23.3	2.7
325 Misc. Power Plant Equipment	30.0	0.0	19.3	2.7
Turkey Point Nuclear-Common				
321 Structures & Improvements	12.1	(2.0)	25.5	6.3
322 Reactor Plant Equipment	12.6	(13.0)	34.8	6.2
323 Turbogenerator Units	13.2	0.0	31.1	5.2
324 Accessory Electric Equipment	13.5	(2.0)	20.3	6.1
325 Misc. Power Plant Equipment	12.8	(2.0)	34.4	5.3
Turkey Point Nuclear-Unit 3				
321 Structures & Improvements	13.2	(2.0)	43.6	4.4
322 Reactor Plant Equipment	12.7	(13.0)	54.5	4.6
323 Turbogenerator Units	12.2	0.0	25.1	6.1
324 Accessory Electric Equipment	13.2	(2.0)	31.2	5.4
325 Misc. Power Plant Equipment	13.5	(2.0)	62.3	2.9
Turkey Point Nuclear-Unit 4				
321 Structures & Improvements	13.2	(2.0)	32.0	5.3

* Denotes Restated Reserve

322 Reactor Plant Equipment	12.8	(13.0)	48.0	5.1
323 Turbogenerator Units	12.6	0.0	30.0	5.6
324 Accessory Electric Equipment	13.2	(2.0)	21.4	6.1
325 Misc. Power Plant Equipment	13.3	(2.0)	47.3	4.1

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00 FLORIDA POWER AND LIGHT COMPANY

1993 DEPRECIATION STUDY

	COMMISSION APPROVED RATES			
	AVERAGE		**ACTUAL**	**REMAINING**
	REMAINING	**NET**	**1-1-94**	**LIFE**
ACCOUNT	**LIFE**	**SALVAGE**	**RESERVE**	**RATE**
TRANSMISSION PLANT				
350.2 Easements	49.0	0.0	15.1	1.7
352.0 Structures and Improvements	36.0	(15.0)	23.6	2.5
353.0 Station Eqpt.	30.0	20.0	26.3	1.8
354.0 Towers and Fixtures	30.0	(15.0)	30.9	2.8
355.0 Poles and Fixtures	29.0	(35.0)	41.9	3.2
356.0 Overhead Cond. & Devices	26.0	(20.0)	40.8	3.0
357.0 Underground Conduit	27.0	0.0	40.8	2.2
358.0 Underground Conductors & Devices	17.5	0.0	51.2	2.8
359.0 Roads and Trails	52.0	0.0	20.5	1.5
DISTRIBUTION PLANT				
361.0 Structures & Improvements	35.0	(5.0)	23.4	2.3
362.0 Station Equipment	29.0	(5.0)	22.6	2.8
364.0 Poles, Towers & Fixtures	30.0	(30.0)	37.1	3.1
365.0 OH Conductors & Devices	27.0	(35.0)	38.6	3.6
366.6 Underground Conduit-Duct Sys.	44.0	0.0	21.7	1.8
366.7 Underground Conduit-Direct Buried	25.0	0.0	25.0	3.0
367.6 Underground Cond. & Devices-In Duct	27.0	10.0	22.2	2.5
367.7 Underground Cond. & Dev.-Direct Buried	17.8	0.0	* 50.9	2.8
368.0 Line Transformers	22.0	(15.0)	33.7	3.7
369.1 Services-Overhead	27.0	(60.0)	46.7	4.2

* Denotes Restated Reserve

	COMMISSION APPROVED RATES			
	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE
ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
369.7 Services-Underground	27.0	(10.0)	27.0	3.1
370.0 Meters	18.5	5.0	42.2	2.9
371.0 Installations on Cust. Premises	10.7	(20.0)	35.4	7.9
373.0 Street Light & Signal Sys.	18.1	(20.0)	41.9	4.3

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01 FLORIDA POWER AND LIGHT COMPANY

1993 DEPRECIATION STUDY

	COMMISSION APPROVED RATES			
	AVERAGE		ACTUAL	REMAINING
	REMAINING	NET	1-1-94	LIFE
ACCOUNT	LIFE	SALVAGE	RESERVE	RATE
GENERAL PLANT				
390.0 Structures & Improvements-FPL	39.0	0.0	15.0	2.2
390.0 Structures & Improvements-LRIC	39.0	0.0	22.2	2.0
392.0 Aircraft-Fixed Wing (Non-Jet)	3.1	50.0	49.1	0.3
392.0 Aircraft-Rotary Wing	6.5	50.0	8.5	6.4
392.0 Aircraft-Fixed Wing (Jet)	6.5	50.0	16.4	5.2
392.1 Transportation-Automobiles	2.1	10.0	34.5	26.4
392.2 Transportation-Light Trucks	3.5	15.0	45.5	11.3
392.3 Transportation-Heavy Trucks	6.8	15.0	39.1	6.8
392.9 Transportation-Trailers	10.5	20.0	39.3	3.9
393.1 Stores Equip-Handling Equip	19.9	10.0	20.1	3.5
394.1 Shop Equip.-Fixed/Stationary	24.0	(10.0)	17.8	3.8
395.1 Lab. Equip.-Fixed/Stationary	30.0	0.0	15.9	2.8
396.1 Power Operated Eq. (Trans.)	6.0	20.0	47.0	5.5
396.8 Other Power Operated Equipment	5.1	20.0	72.2	1.5
397.1 Communications Equipment-Other	12.9	0.0	29.3	5.5
397.3 Communications Eqpt.-Official	5.1	0.0	27.4	14.2
397.8 Communications Eqpt.-Fiber	7.8	5.0	20.9	9.5

ACCOUNT	COMMISSION APPROVED RATES AVERAGE REMAINING LIFE	NET SALVAGE	ACTUAL 1-1-94 RESERVE	REMAINING LIFE RATE
Optics				
AMORTIZABLE PLANT				
391.1 Office Furniture				7 Yr. Amortization
391.2 Office Equipment				5 Yr. Amortization
391.3 Computers				7 Yr. Amortization
391.4 Duplicating & Mailing Equipment				7 Yr. Amortization
391.5 EDP Equipment				5 Yr. Amortization
392.7 Transportation Equipment-Marine Equip.				5 Yr. Amortization
393.2 Storage Equipment				7 Yr. Amortization
393.3 Portable Handling Equip.				7 Yr. Amortization
394.2 Shop Equipment-Portable Handling				7 Yr. Amortization
395.2 Portable Laboratory Equip.				7 Yr. Amortization
398.0 Miscellaneous Equip.				7 Yr. Amortization

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02 FLORIDA POWER AND LIGHT COMPANY

1993 DEPRECIATION STUDY

COMMISSION APPROVED RECOVERY SCHEDULES

ACCOUNT	1-1-94 INVESTMENT ($)	1-1-94 RESERVE ($)	EXPECTED SALVAGE ($)	NET TO BE RECOVERED ($)	PERIOD OF RECOVERY (Yrs.)
St. Lucie Steam Generators	19,179,904	10,766,322	(53,600,000)	62,013,582	4.5 Yrs.
Cutler-Unit 4	0	(729)	0	729	1 Yr.
Sanford-Unit 1	0	(1,116)	0	1,116	1 Yr.
Asbestos and Overhauls					

	1-1-94 INVESTMENT ($)	1-1-94 RESERVE ($)	EXPECTED SALVAGE ($)	NET TO BE RECOVERED ($)	PERIOD OF RECOVERY (Yrs.)
1994-1997	6,076,843	5,171,136	(2,673,885)	3,579,592	4 Yrs.
367.7-Silicone					
Injection	13,602,490	1,475,268	0	12,127,222	8 Yrs.
TOTAL	38,859,237	17,410,881	(56,273,885)	77,722,241	

03 COMMISSION APPROVED

CORRECTIVE RESERVE TRANSFERS

ACCOUNT	1-1-94 BOOK RESERVE	APPROVED TRANSFERS	1-1-94 ADJUSTED RESERVE
Ft. Myers-			
Common			
Account 314	$ 81,329	$ (54,413)	$ 26,916
Account 315	207,157	54,413	261,570
Pt Everglades-			
Common			
Account 311	6,513,072	457,425	6,970,497
Pt Everglades-			
Unit 1			
Account 311	1,893,211	(457,425)	1,435,786
Riviera-Unit 3			
Account 311	523,692	(401,515)	122,177
Riviera-Unit 4			
Account 311	368,339	(272,718)	95,621
Ft. Myers-			
Unit 1			
Account 311	1,089,743	at (552,618)	537,125
Cutler-Unit 4	*(568,762)	568,033	*(729)

* Denotes dismantlement reserve.

at Represents remaining unrecovered costs associated with pre-1994 major overhaul and asbestos abatement projects.

ACCOUNT	1-1-94 BOOK RESERVE	APPROVED TRANSFERS	1-1-94 ADJUSTED RESERVE
Riviera-Unit 1	*(22,891)	22,891	* -0-
Pre-1994 O'haul/Asbest. Abatement Unrecovered Costs	at (46,908,506)	635,927	(46,272,579)

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End of Document

Melinda Marzicola

ATTACHMENT B

1995 Fla. PUC LEXIS 632

Florida Public Service Commission

April 12, 1995

DOCKET NO. 950213-EI; ORDER NO. PSC-95-0475-FOF-EI

FL Public Service Commission Decisions

Reporter
1995 Fla. PUC LEXIS 632 *

In Re: Petition for Approval of Recovery Schedule for Energy Management System by Tampa Electric Company

Core Terms

amortize, depreciation expense, calculate, transmission, depreciate, notice, electric company, agency's action, seven years, five year, years old, one year, retirement, technology, electric, network, vintage, embed, plant, has, was

Panel: The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman; J. TERRY DEASON; JULIA L. JOHNSON; DIANE K. KIESLING

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER GRANTING APPROVAL OF RECOVERY SCHEDULE

BY THE COMMISSION:

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

On February 24, 1995, Tampa Electric Company (TECO or the Company) filed a request for approval of a recovery schedule for its Energy Management System (EMS). In accordance with Rule 25-6.0436 (10)(a), Florida Administrative Code, TECO has requested a one year write-off of the calculated reserve deficiency associated with the present EMS. The currently prescribed depreciation rate is based on an average service life of 15 years and became effective January 1, 1991. This was the projected life expectancy for this type of technology at that time. **[*2]** The calculated reserve deficiency results from using new expected life parameters.

EMS is an installation designed for the specific purpose of facilitating the systematic transmission, distribution and delivery of electric energy to TECO's customers. It monitors the power network, automatically controls generation and interchange, forecasts the power network state and performs other specialized functions. The current environment of open transmission access and transmission constraints demands flexibility and speed in the Company's day-to-day operations. The present EMS technology is approximately fifteen years old and the computers are eight years old. According to the Company, there is no vendor support to develop new software. An

ATTACHMENT B

EMS Strategic Plan to replace EMS components in a phased migration to workstation-based computer platforms has been implemented by TECO and will take place over the next five years.

TECO proposes a one year recovery schedule effective January 1, 1995 to correct the calculated reserve deficiency associated with the EMS scheduled for retirement in 2000. This will bring the account reserve more nearly in line with its calculated theoretical level. The main **[*3]** reason for selecting the effective date of January 1, 1995 is that this $ 5 million increase in depreciation expense will be offset by a decrease of approximately $ 5.5 million in the amortizable general plant depreciation expense. With the implementation in 1988 of the retirement unit rule for electric companies (Rule *25-6.0142, Florida Administrative Code*), five and seven year amortization periods were established for certain general plant accounts. The net embedded investments represented by vintages prior to 1988 were to be amortized over those same periods. Information provided by TECO indicates that the net embedded investments subject to a seven year amortization were fully amortized as of December 31, 1994. Further, the 1989 vintage of computer and peripheral equipment subject to a five year amortization was also fully amortized by December 31, 1994. These amortizations will not continue in 1995 thus permitting the Company to increase the depreciation expense for EMS while maintaining essentially the same bottom-line level of depreciation expense as 1994.

At the present time, TECO does not propose to change the depreciation rate **[*4]** for this equipment, but plans to address a rate change and the capital recovery position of this equipment in its depreciation study filing in June 1995. We, therefore, approve TECO's one-time amortization of $ 5 million in 1995.

Based on the foregoing, it is

ORDERED that Tampa Electric Company's proposed one-year capital recovery schedule is approved. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective unless an appropriate petition, in the form provided by Rule *25-22.036, Florida Administrative Code*, is received by the Director, Division of Records and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on the date set forth in the "Notice of Further Proceedings or Judicial Review" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket should be closed.

By ORDER of the Florida Public Service Commission, this 12th day of April, 1995.

FL Public Service Commission Decisions

End of Document

1996 Fla. PUC LEXIS 617

Florida Public Service Commission

April 2, 1996

DOCKET NO. 950359-EI; ORDER NO. PSC-96-0461-FOF-EI, 96 FPSC 4:54

FL Public Service Commission Decisions

Reporter
1996 Fla. PUC LEXIS 617 *

In Re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company

Core Terms

nuclear, retail sale, base rate, amortize, forecast, was, amortization expense, additional expense, annual, band, depreciation expense, write off, calculate, strand, staff

Panel: ; The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman, J. TERRY DEASON, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

Opinion

FINAL ORDER APPROVING PROPOSAL TO RESOLVE ISSUES RELATING TO FLORIDA POWER & LIGHT COMPANY'S PETITION TO ESTABLISH A NUCLEAR AMORTIZATION SCHEDULE

BY THE COMMISSION:

On March 31, 1995, Florida Power & Light Company (FPL or Company) filed its petition for authorization to establish an amortization schedule, effective January 1, 1995, for its nuclear generating units to address the potential for stranded investment. FPL requested that it be allowed to charge and record for its nuclear generating units a fixed and permanent $ 30 million annual amortization expense. In addition, for 1995 and 1996, the Company requested approval to charge and record an additional amount of amortization expense equal to 100% of base rate revenues produced by retail sales between FPL's current "low band" and "most likely sales forecast" and 50% of the base rate revenues produced by retail sales above FPL's current "most likely sales forecast" for 1995 and 1996.

In Order No. PSC-95-0672-FOF-EI PSC, we approved the Company's **[*2]** request to begin preliminary implementation of the amortization schedule. We allowed the Company to record amortization expense in a separate subaccount of the Accumulated Provision for Depreciation for each nuclear generating unit. The account where the expense would be recorded was to be determined by us at the hearing.

At the hearing held in this docket on March 13, 1996, the following proposal was presented to resolve all issues identified by the Company and our staff:

ATTACHMENT B

1. FPL shall apply the additional 1995 depreciation expense, of approximately $ 126 million, booked in accord with preliminary implementation approved in Order PSC-95-0672-FOF-EI to the reserve deficiency in nuclear production, which was calculated to be $ 175,304,010 as of January 1, 1994.

2. Commencing in 1996, FPL shall record an annual $ 30 million in nuclear amortization. The expense amount is final; however, the account to which it is booked remains subject to determination by the Commission in a future proceeding such as a generic stranded cost docket.

3. FPL shall record an additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most **[*3]** likely sales forecast" for 1996 as filed in this docket, and at least 50% of the base rate revenues produced by retail sales above FPL's "most likely sales forecast" for 1996 as filed in this docket. Any additional expense recorded as a result of this provision will be first applied to correct the remaining reserve deficiency existing in nuclear production; second, to correct the reserve deficiency existing in FPL's other production facilities, which was calculated to be $ 60,338,330 as of January 1, 1994; third, to write off the net amount of book-tax timing differences that were flowed through in prior years and remain to be turned around in future periods; and fourth, to write off the Unamortized Loss on Reacquired Debt.

At the hearing, our staff recommended approval of the proposal. Upon consideration, we believe that the proposal represents a reasonable resolution of the issues and find that it should be approved.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company shall apply the additional 1995 depreciation expense, of approximately $ 126 million authorized pursuant to Order PSC-95-0672-FOF-EI to the reserve **[*4]** deficiency in nuclear production. It is further

ORDERED that commencing 1996, Florida Power & Light Company shall record an annual $ 30 million in nuclear amortization. The account to which the amortization is booked shall be subject to determination by the Commission in a future proceeding. It is further

ORDERED that Florida Power & Light Company shall record an additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most likely sales forecast" for 1996, and at least 50% of the base rate revenues produced by retail sales above FPL's "most likely sales forecast" for 1996 as more fully described in the body of this Order. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission, this 2nd day of April, 1996.

BLANCA S. BAYO, Director

Division of Records and Reporting

1997 Fla. PUC LEXIS 510

Florida Public Service Commission

April 29, 1997

DOCKET NO. 970410-EI; ORDER NO. PSC-97-0499-FOF-EI, 97 FPSC 4:640

FL Public Service Commission Decisions

Reporter
1997 Fla. PUC LEXIS 510 *

In Re: Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company

Core Terms

retail, nuclear, depreciate, forecast, additional expense, decommissioning, base rate

Panel: The following Commissioners participated in the disposition of this matter: JULIA L. JOHNSON, Chairman, SUSAN F. CLARK, J. TERRY DEASON, JOE GARCIA, DIANE K. KIESLING

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER EXTENDING PLAN TO RECORD ADDITIONAL EXPENSES THROUGH 1998 AND 1999

BY THE COMMISSION:

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

CASE BACKGROUND

In Docket No. 950359-EI, the Commission approved a proposal by Florida Power & Light Company (FPL) that resolved all of the identified issues regarding FPL's petition to establish a nuclear amortization schedule. By Order No. PSC-96-0461-FOF-EI, issued April 2, 1996, FPL was required (1) to book additional 1995 depreciation expense to the reserve deficiency in nuclear production; (2) to record, commencing in 1996, an annual $ 30 million in nuclear amortization, subject to final determination by the Commission as **[*2]** to the accounts to which it is to be booked; and (3) to record an additional expense in 1996 and 1997 based on differences between actual and forecasted revenues, to be applied to specific items in a specific order.

In the instant case, FPL, the Office of Public Counsel, and the Commission staff met to discuss a continuation of the plan approved in Docket No. 950359-EI. AmeriSteel, Inc., an FPL customer, also participated in the review of the plan as an interested person. The current proposal (Attachment A) would extend and modify the plan through 1998 and 1999.

ATTACHMENT B

In general, the proposal extends the currently approved plan for 1996 and 1997 for an additional two years through 1999. Essentially, FPL proposes to continue to record additional retail expense equal to 100% of the base rate revenues produced by actual retail sales between its "low band" and "most likely sales forecast" and at least 50% of the base rate revenues produced by actual retail sales above FPL's "most likely sales forecast" forecasted for 1996 as filed in Docket No. 950359-EI. This provision remains the same.

However, there are some differences between the items to which the additional expense will be applied **[*3]** as well as a modification of their priority. The first priority will be to correct any depreciation reserve deficiency quantified in an approved depreciation study order. Previously, the correction of the nuclear depreciation reserve deficiency had been given the first priority. The priority of the other items in the previously approved plan remains the same.

Several additional items have been added to the list. Item 4 involves the correction of any reserve deficiency in FPL's fossil dismantlement reserves. Item 5 is the correction of any reserve deficiency in FPL's nuclear decommissioning reserves. In the event that any revenues remain to be disposed of, they are to be recorded as an expense in an unspecified depreciation reserve account for production plant to be allocated to specific accounts at a later date by the Commission.

Although it is not specifically addressed in the proposal, FPL is still obligated to record an additional $ 30 million annually in nuclear amortization until such time as the Commission orders otherwise per the terms of the plan approved in Order No. PSC-96-0461-FOF-EI. In addition, all amounts remain subject to review and audit by the Commission. **[*4]** This plan neither precludes an earnings review nor a review of the plan during the context of a proceeding to reset base rates. In the event that any legislative, administrative, or judicial action authorizing retail wheeling or deregulating the retail electric market is approved for Florida, the terms of this proposal may be altered or terminated upon the Commission's own motion or by the approval of a petition filed with the Commission.

We believe that this plan is appropriate because it mitigates past deficiencies with Commission prescribed depreciation, dismantlement, and nuclear decommissioning accruals. The plan also brings FPL's accounting in line with non-regulated companies by eliminating regulatory assets such as deferred refinancing costs and the assets associated with previously flowed through taxes. These accounting adjustments will facilitate the establishment of a level "accounting" playing field between FPL and possible non-regulated competitors.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the proposal (Attachment A) that extends and modifies the previously approved FPL plan for 1996 and 1997 concerning the recording of **[*5]** certain additional expenses for the years 1998 and 1999 is approved. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective unless an appropriate petition, in the form provided by Rule *25-22.036, Florida Administrative Code*, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings or Judicial Review" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission, this 29th day of April, 1997.

BLANCA S. BAYO, Director

Division of Records and Reporting

FPL 1998 and 1999 Plan

FPL shall record an additional retail expense in 1998 and 1999 equal to 1005'o of the base rate revenues produced by retail sales between its "low band" ($ 3.1409 billion) and "most likely sales forecast" ($ 3.2241 billion) and at least 50% of the base rate revenues produced by retail sales above FPL's "most likely sales forecast" forecasted **[*6]** for 1996 as filed in Docket No. 950359-EI. Any additional retail expense recorded as a result of this provision will be applied to the retail portion of the following listed in priority order:

1. Correction of any depreciation reserve deficiency resulting from an approved depreciation study order;

2. Writing off the net amounts of book-tax timing differences that were flowed through in prior years and remain to be turned around in future periods;

3. Writing off the Unamortized Loss on Reacquired Debt;

4. Correction of the reserve deficiency, if any, existing in FPL's fossil dismantlement reserves;

5. Correction of the reserve deficiency, if any, existing in FPL's nuclear decommissioning reserves. Any additional expenses recorded under this plan for nuclear decommissioning shall be funded on an after tax basis. Effective January 1, 1998, all debit deferred taxes resulting from amounts contained in decommissioning funds shall be excluded for surveillance purposes;

6. In the event revenues from the forecast bands are greater than the expenses identified herein, the remaining expenses shall be recorded in an unspecified depreciation reserve to be allocated at a later **[*7]** date.

A comprehensive fossil dismantlement study and a comprehensive nuclear decommissioning study shall be filed by October 1, 1998.

Upon the Commission's own motion or a petition filed with the Commission, the recording of the additional expense under this plan may be altered or terminated by the Commission in the event that legislative, administrative or judicial action authorizing retail wheeling or deregulating the retail electric market is approved for Florida.

FL Public Service Commission Decisions

End of Document

1999 Fla. PUC LEXIS 77

Florida Public Service Commission

January 8, 1999

DOCKET NO. 971660-EI; ORDER NO. PSC-99-0073-FOF-EI, 99 FPSC 1:427

FL Public Service Commission Decisions

Reporter
1999 Fla. PUC LEXIS 77 *

In re: 1997 depreciation study by Florida Power & Light Company

Core Terms

depreciate, amortize, company's, revise, accumulate, has, nuclear, edit, was, flowback, plant, depreciation expense, calculate, salvage, recommend

Panel: ; The following Commissioners participated in the disposition of this matter: JULIA L. JOHNSON, Chairman, J. TERRY DEASON, SUSAN F. CLARK, JOE GARCIA, E. LEON JACOBS, JR.

Opinion

[EDITOR'S NOTE: THE ORIGINAL SLIP OPINION CONTAINED ILLEGIBLE WORDS AND/OR MISSING TEXT. THE LEXIS SERVICE WILL PLACE THE CORRECTED VERSION ON-LINE UPON RECEIPT.]

NOTICE OF PROPOSED AGENCY ACTION ORDER APPROVING FINAL DEPRECIATION RATES FOR FLORIDA POWER & LIGHT COMPANY

BY THE COMMISSION:

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

I. CASE BACKGROUND

Rule *25-6.0436, Florida Administrative Code*, requires Investor Owned Utilities to file comprehensive depreciation studies at least once every four years. On December 26, 1997, Florida Power and Light Company (FPL or the company) filed its regular depreciation study in accordance with this rule. FPL also requested **[*2]** preliminary implementation of its proposed depreciation rates and amortization/ recovery schedules as of January 1, 1998, in accordance with Rule 25-6.0436(5), Florida Administrative Code. By Order No. PSC-98-0901-PCO-EI, issued July 6, 1998, that request was approved. The docket remained open pending review and final action concerning the appropriate depreciation rates and recovery schedules under consideration.

II. REVISION TO RATES IMPLEMENTED ON A PRELIMINARY BASIS

We find that the depreciation rates approved for preliminary implementation must be revised. By Order No. PSC-98-0901-PCO-EI, preliminary implementation of depreciation rates, capital recovery schedules, and amortization schedules were established. Expenses implemented on a preliminary basis were to be trued-up upon final action in this docket. The review of the company's study has been completed and this order constitutes the outcome thereof.

III. IMPLEMENTATION DATE

The implementation date for the new depreciation rates and recovery/amortization schedules shall be January 1, 1998. Company data and related calculations abut the January 1, 1998, date. **[*3]** This date of implementation is the earliest practicable date for utilizing the revised rates and recovery/amortization schedules.

IV. RESERVE ALLOCATIONS

Reserve allocations shall be made as shown on Attachment A, pages 10-19, to correct the quantified reserve deficiencies. These allocations relate to the additional depreciation expense recorded in accordance with Order No. PSC-96-0461-FOF-EI, issued April 2, 1996, the accumulated reserve adjustments attributable to interest synchronization related to Investment Tax Credits (ITCs) recorded in accordance with Order No. 16257, issued June 19, 1986, and the additional depreciation expense recorded in accordance with Order No. PSC-98-0027-FOF-EI, issued January 5, 1998.

The study afforded us the opportunity to review the reserve status of all production sites and all transmission, distribution, and general plant accounts to determine the need for corrective reserve measures. Due to the effects reserve transfers may have on jurisdictional separations, purchase power agreements, or other lease arrangements, our approach to reserve allocations is that, ideally they be made between accounts of a given unit or function. The allocations **[*4]** discussed below and shown on Attachment A, pages 10-19, address major imbalances generally brought about by transfers associated with the unitization of certain production plants and past mis-estimates of life and salvage factors.

By Order No. PSC-96-0461-FOF-EI, in Docket No. 950359-EI, FPL was authorized to record additional depreciation expense of $ 175.3 million for Nuclear Production and $ 60.3 million for Other Production to correct reserve deficiencies. As part of this current filing, the company has proposed the allocation of that additional expense to specific accounts. The theoretical reserve calculations and the expense allocations are acceptable. These allocations are approved.

Further, as part of this current filing, FPL calculated additional reserve deficiencies for its steam and nuclear production accounts in the amount of $ 198.8 million ($ 51.1 million for nuclear and $ 147.7 million for steam). FPL has proposed that these deficiencies be corrected by Order No. PSC-98-0027-FOF-EI, the Plan, in Docket No. 970410-EI. This order authorized the company to correct reserve deficiencies resulting from an approved depreciation study order. By Order No. PSC-98-0901-PCO-EI, **[*5]** issued July 6, 1998, in this docket granting preliminary implementation of FPL's proposed depreciation rates, the company began writing-off these calculated perceived deficiencies January 1, 1998.

We believe that other monies are available for use in correcting the identified reserve deficiencies and should be used before correction pursuant to the Plan. First, by Order No. 16257, issued June 19, 1986, Docket No. 840086-EI, et al., we decided that depreciation reserve adjustments should be used to offset revenue requirements associated with the interest synchronization of ITCs until base rates were changed. In accordance with this order, FPL has been accumulating reserve adjustments attributable to ITCs to a bottom-line reserve account. As of January 1, 1994, the accumulated amounts for the period 1990-1993 totaled $ 8,326,512 on a System basis. In FPL's last depreciation rate proceeding in Docket 931231-EI, those accumulated amounts were subject to reallocation to specific accounts. However, by Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, Docket No. 931231-EI, we decided that these ITC monies should continue to accumulate in a bottom-line reserve with disposition **[*6]** to be determined at a later date. The on-going monthly adjustments of $ 171,785 have therefore continued to be recorded. As of January 1, 1999, the accumulated ITC amount will be $ 18,633,612 on a System basis. We find that this amount shall be allocated to help correct the reserve deficiencies quantified and identified on Attachment A. After allocation of the accumulated $ 18.6 million of ITC monies, the remaining deficiencies shall be addressed pursuant to the plan approved in Order No. PSC-98-0027-FOF-EI.

Second, as part of Order No. PSC-96-0461-FOF-EI, FPL was authorized to record an annual $ 30 million in nuclear amortization expense, beginning January 1, 1996. The expense amount was final; however, the accounts to which the accumulated amount was to be booked remained subject to determination in a future proceeding such as a generic stranded cost docket. As of January 1, 1999, the company will have recorded $ 90 million in additional nuclear amortization. Because there has been no stranded cost docket opened, Commission staff initially recommended that the appropriate action was for this expense amount to be allocated to the reserve deficiencies quantified in this proceeding. **[*7]** However, during the December 1, 1998, Agenda Conference on Docket No. 981390-EI, In Re: Investigation into the Equity Ratio and Return on Equity of Florida Power & Light Company, FPL requested that a decision regarding this allocation be deferred. During the December 1, 1998, Agenda Conference for this Docket, Commission staff concurred with FPL's request for deferral. We agree. Since there is no impact on depreciation rates, we will defer the decision on the accounts to which the accumulated nuclear expense will be booked until after a final decision has been rendered in Docket No. 981390-EI.

V. DEPRECIATION RATES AND RECOVERY/AMORTIZATION SCHEDULES

The appropriate depreciation rates and recovery/amortization schedules shall be as set forth below. The lives, net salvages, reserves, and resultant depreciation rates are shown on Attachment B, pages 20-29. Reserve positions have been restated to reflect the corrective action taken herein. Resulting expenses from preliminary implementation shall be trued-up accordingly.

This finding is the result of a comprehensive review of the company's submitted study.

A. Production

FPL's mechanized property record system affords **[*8]** it the ability to provide in-depth stratified information for the assets in an account at a specific unit. A generating station, or a generating unit, can be looked at as a box containing an assortment of various types of assets which can be expected to experience varied service lives. Stratification is the determination that this account at this unit has so many dollars of pumps, piping, rotors, or structures, etc., with each of these strata expected to have a certain service life. The life of the account can then be arrived at by compositing expectations of the various strata.

The company's projections of lives for the various strata, and of expected interim net salvage values are reasonable. In general, the company's operating philosophy has not radically changed since the last comprehensive study. As a result, there has not been any major overall change in planning for the plants operating at the present time. Significant changes have come from repowering plans for the Ft. Myers and Sanford sites, and from experience gained from installations of new technologies.

The Ft. Myers Units are scheduled to be back in service by year-end 2001 after repowering; and the Sanford **[*9]** Units are expected to be returned to service by year-end 2003. The repowering projects will increase the name plate ratings from 558 MW to 960 MW for Ft. Myers and from 586 MW to 960 MW for Sanford.

For the retirements associated with each repowering project, FPL's proposal for recovery by end-of-year 2001 for Ft. Myers and end-of-year 2003 for Sanford is in line with current planning. The recommended recovery schedules are designed to recover the associated net investments over the remaining service periods of 3.5 years and 5.5 years, respectively.

This current study recognizes changes seen in the service life expected from certain installations which incorporate leading edge technologies. For example, a six year replacement interval was previously associated with the transition nozzles in the combined cycle units at the Martin Plant Site. With this filing, a five year replacement interval is established for these nozzles. The change is a result of the company's experience with the performance of this technology in this setting, including the hours of operation which result from dispatch of the particular unit. In general, the units have performed with better heat rate and have **[*10]** been utilized more than was expected before the units came on line.

For the nuclear units, we note that a decision whether or not to seek life extension may need to be made prior to the time of filing of the next depreciation study, at least in the case of the Turkey Point nuclear generating units. At present, license termination is scheduled for 2012 for Turkey Point 3, and the following year for Unit 4. Both the recovery of investment for plant equipment, and the decommissioning provisions, become critical when a shutdown date is firmed up, or when it is delayed. FPL shall notify the Commission in a timely manner, of any decision relating to these matters so appropriate recovery can be addressed.

B. Transmission and Distribution

The life and salvage parameters FPL proposed for the accounts in these functions were conservative. Many of the accounts reflect the status quo. In other words, the service life and salvage values approved in the last represcription are being maintained. The recommended remaining lives simply reflect an update of activity. For the remaining accounts, the proposals reflect a move more in line with the range of industry expectations.

Differences **[*11]** between recommended life values and those approved on a preliminary basis exist for Easements (Account 350.1), Station Equipment (Account 353), Poles and Fixtures (Account 354), and Roads and Trails (Account 359). These accounts have experienced insufficient retirement activity to perform any meaningful statistical analyses. Recommended remaining lives and salvage values are therefore based on judgement and industry expectations.

C. General Plant Amortization

FPL has proposed expanding the amortization currently in place for certain general plant accounts. Specifically, the January 1, 1998, net unrecovered depreciable portions of Accounts 393 (Stores), 394 (Tools, Shop, & Garage), and 397 (Official Communications) are proposed to be amortized over seven years. Subsequent additions will be maintained by vintage and amortized accordingly. These accounts represent minor investments of numerous items that are difficult to track or trace. On a going forward basis, each vintage year's additions associated with each account will be amortized over a like period of time. The use of amortization is acceptable and in line with our efforts to simplify the depreciation study process, where **[*12]** possible.

VI. AMORTIZATION OF INVESTMENT TAX CREDITS AND EXCESS DEFERRED INCOME TAXES

As previously stated, revisions shall be made to the company's remaining lives, to be effective January 1, 1998. Revising a utility's book depreciation lives generally results in a change in its rate of ITC amortization and flowback of Excess Deferred Income Taxes (EDIT) in order to comply with the normalization requirements of the Internal Revenue Code (IRC) and underlying Regulations (REGs) found in Sections 46, 167, and 168 and 1.46, 1.67, and 1.68, respectively.

Section 46(f)(6), IRC, states that the amortization of ITCs should be determined by the period of time actually used in computing depreciation expense for rate making purposes and on the regulated books of the utility. Since remaining lives are being changed, it is also important to change the amortization of ITCs to avoid violation of the provisions of sections 46 and 1.46, IRC and REGs, respectively.

Section 203(3) of the Tax Reform Act of 1986 (the Act) prohibits rapid flowback of depreciation related (protected) EDIT. Further, Rule 25-14.013, Accounting for Deferred Income Taxes Under SFAS **[*13]** 109, Florida Administrative Code, generally prohibits EDIT from being written off any faster than allowed under the Act. The Act, SFAS 109, and Rule *25-14.013, Florida Administrative Code*, regulate the flowback of EDIT. Therefore, the flowback of EDIT shall be adjusted to comply with the Act, SFAS 109, and Rule *25-14.013, Florida Administrative Code*.

The Internal Revenue Service, independent outside auditors, and the Commission look to a company's books and records and at the orders and rules of the jurisdictional regulatory authorities to determine if the books and records are maintained in the appropriate manner and to determine the intent of the regulatory bodies in regard to normalization. In order for there to be a clear audit trail, the company shall revise ITCs and EDIT amortization and produce work papers to show how the revisions were made.

Therefore, we find that the current amortization of ITCs and the flowback of EDIT shall be revised to reflect the approved depreciation rates and recovery schedules. The utility shall file detailed calculations of the revised ITC amortization **[*14]** and flowback of EDIT at the same time it files its surveillance report covering the period ending December 31, 1998.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's request to implement, effective January 1, 1998, final depreciation rates and general plant amortization as shown on Attachments A, B, and C is granted. It is further

ORDERED by the Florida Public Service Commission that Florida Power & Light's depreciation rates and recovery/amortization schedules implemented by Order No. PSC-98-0901-PCO-EI are hereby revised as set forth in Attachment A to this order. It is further,

ORDERED that the reserve amounts related to the additional depreciation expense recorded in accordance with Order No. PSC-96-0461-FOF-EI, the accumulated reserve adjustments attributable to the synchronization of Investment Tax Credits recorded in accordance with Order No. 16257, and the additional depreciation expense recorded in accordance with Order No. PSC-98-0027-FOF-EI and shown on Attachment A shall be transferred as shown on Attachment A. Any remaining deficiencies shall be addressed according to the Plan. It is further,

ORDERED **[*15]** that allocation of the $ 90 million in nuclear amortization accumulated as provided by Order No. PSC-96-0461-FOF-EI shall be deferred until after a final decision is rendered in Docket No. 981390-EI. It is further,

ORDERED that the current amortization of Investment Tax Credits and Excess Deferred Income Taxes shall be revised to reflect the approved depreciation rates. It is further,

ORDERED that FP&L shall file detailed calculations of the revised Investment Tax Credits amortization and flowback of Excess Deferred Income Taxes at the same time it files its surveillance report covering the period ending December 31, 1998. It is further,

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

ORDERED that in the event this Order **[*16]** becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 8th day of January, 1999.

BLANCA S. BAYO, Director

Division of Records and Reporting

[ILLEGIBLE SLIP OP. PAGES 433, 434, 435, 436, 437, 438, 439, 440, 441, 442, 443, 444, 445, 446, 447, 448, 449, 450,451, 452]

ATTACHMENT C

FLORIDA POWER AND LIGHT COMPANY 1997 DEPRECIATION STUDY

APPROVED RECOVERY SCHEDULES

ACCOUNT	1-1-98 INVESTMENT ([)	1-1-98 RESERVE ([)	PERIOD OF RECOVERY (YRS)
Ft. Myers Repowering Retirements	43,557,129	35,506,998	3.5
Sanford Repowering Retirements	43,727,901	36,556,022	5.5
TOTAL	87,315,030	72,063,020	

FL Public Service Commission Decisions

End of Document

Florida Public Service Commission

February 14, 2000

DOCKET NO. 981166-EI; ORDER NO. PSC-00-0293-PAA-EI, 00 FPSC 2:276

FL Public Service Commission Decisions

Reporter
2000 Fla. PUC LEXIS 153 *

In re: Request for approval of revised fossil dismantlement expense accruals, effective 1/1/99, by Florida Power & Light Company.

Core Terms

dismantlement, fossil, annual, accrual, update, was, cost estimate, contingency, site-specific, cost

Panel: The following Commissioners participated in the disposition of this matter: JOE GARCIA, Chairman, J. TERRY DEASON, SUSAN F. CLARK, E. LEON JACOBS, JR.

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER REVISING FOSSIL DISMANTLEMENT ACCRUALS

BY THE COMMISSION:

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

I. CASE BACKGROUND

By Order No. PSC-95-1532-FOF-EI, issued December 12, 1995, in Docket No. 941343-EI, Florida Power & Light Company (FPL or company) was required to file its fossil dismantlement studies on December 29, 1999. Subsequently, by Order No. PSC-98-0027-FOF-EI, issued on January 5, 1998, in Docket No. 970410-EI, FPL was directed to file its fossil dismantlement studies no later than October 1, 1998. FPL's request for approval of a revised fossil dismantlement accrual resulting from its updated site-specific dismantlement studies was filed on September 17, **[*2]** 1998.

By Order No. PSC-99-0519-AS-EI, issued March 17, 1999 in Docket No. 990067-EI, we approved a Stipulation and Settlement (Stipulation) between FPL, the Office of Public Counsel, the Florida Industrial Power User's Group, and the Coalition for Equitable Rates. The Stipulation addressed a number of earnings and rate-related issues. By Paragraph 8 of the Stipulation, the parties agreed that FPL's fossil dismantlement expense would be capped at the currently approved level. The current annual dismantlement accruals of $ 16,962,106 were approved by Order No. PSC-95-1532-FOF-EI, issued December 12, 1995, in Docket No. 941343-EI. The Stipulation does not preclude a reduction in annual accrual amounts, if appropriate. This Order addresses our review of FPL's current fossil dismantlement studies.

ATTACHMENT B

II. RESERVE ALLOCATIONS

By Order No. PSC-98-0027-FOF-EI, issued January 5, 1998, in Docket No. 970410-EI, FPL was authorized to record additional expense amounts to correct the calculated historical deficiency brought about by failure in the past to adequately provide for the cost of dismantlement. As a result, FPL has increased its dismantlement reserve by $ 37,515,232 jurisdictional **[*3]** ($ 38,150,825 Total System). Attachment A, which is incorporated by reference herein, shows the approved allocation of this additional dismantlement expense amount to each production unit. The allocations are based on calculated reserves that are in accord with generally accepted theoretical reserve calculations. Therefore, we find that the reserve allocations shown on Attachment A shall be approved.

III. APPROPRIATE ANNUAL PROVISION FOR DISMANTLEMENT

The approved annual provision for dismantlement was developed using the corrected dismantlement reserve position, company updated dismantlement cost estimates, a contingency factor of 16%, and the latest inflation forecasts for all fossil plant sites. The decrease in the annual provision is due, primarily, to correction of the reserve deficiency and changes in the DRI forecasts.

Updated dismantlement cost estimates of $ 282,163,825 are based on site-specific studies and reflect an increase of about 16% over the 1994 estimates of $ 243,199,381. The increase is due primarily to increased labor rates based on the 1998 Means Union wages adjusted to reflect the geographical location of each site, increased disposal costs for concrete **[*4]** and non-hazardous insulation based on current landfill fees and hauling charges, and a general decrease in salvageable material values.

FPL's current dismantlement accruals are based on cost estimates assuming a 16% weighted average contingency factor. Inherent in its updated cost estimates, FPL continues use of the same contingency factor. The factor is based on applying specific contingency factors as recommended by the Atomic Industrial Forum/National Environmental Studies Project report AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" to individual cost categories that are applicable to fossil dismantlement. Additionally, a 20% contingency factor was assumed for asbestos removal since the report does not include specific factors for this cost category. We have utilized a 16% weighted average contingency factor to determine the total estimated costs for the dismantlement of FPL's fossil-fueled generating stations.

FPL's dismantlement study calculated revised annual dismantlement accruals based on DRI inflation forecasts from the Fall/Winter 1997-1998 publication. We updated the DRI inflation factors using the latest **[*5]** available data from the DRI Summer 1999 publication. The effect of the DRI update is a decrease in the annual accrual of $ 1,787,166.

The total dismantlement annual accrual based on FPL's current site-specific dismantlement study cost estimates, the DRI Summer 1999 inflation factors, and the use of a dismantlement book reserve position is $ 22,562,448. However, correction of the reserve deficiencies as authorized by Order No. PSC-98-0027-FOF-EI, results in a total annual dismantlement accrual of $ 15,574,015. Accordingly, we find that the appropriate annual Total System provision for dismantlement is $ 15,574,015, effective January 1, 1999.

IV. FILING DATE FOR FPL'S NEXT FOSSIL DISMANTLEMENT SITE-SPECIFIC STUDIES

By Order No. PSC-95-1532-FOF-EI, issued on December 12, 1995 in Docket No. 941343-EI, we approved FPL's request to file updated fossil dismantlement studies on a four-year cycle beginning December 29, 1994. Subsequently, by Order No. PSC-98-0027-FOF-EI, issued on January 5, 1998 in Docket No. 970410-EI, FPL was required to file its fossil dismantlement study no later than October 1, 1998. In accordance with this order, FPL filed its current studies on September 17, **[*6]** 1998. Therefore, we find that the next regularly scheduled fossil dismantlement site-specific studies shall be filed no later than September 17, 2002.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the reserve allocations shown on Attachment A, which is incorporated by reference herein, are approved. It is further

ORDERED that the annual provision for dismantlement of $ 15,574,015, shown on Attachment B, which is incorporated by reference herein, is approved, effective January 1, 1999. It is further

ORDERED that the next regularly scheduled fossil dismantlement site-specific studies for Florida Power & Light Company shall be filed no later than September 17, 2002. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule *28-106.201, Florida Administrative Code*, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in **[*7]** the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 14th Day of February, 2000.

BLANCA S. BAYO, Director

Division of Records and Reporting

Attachment A

FLORIDA POWER AND LIGHT COMPANY FOSSIL DISMANTLEMENT RESERVE ALLOCATION

	BOOK RESERVE	**APPROVED RESERVE ALLOCATIO**	**RESTATED RESERVE**
Steam Production			
Cutler	5,808,799	(1,887,577)	7,696,376
Port Everglades	24,454,523	(4,557,397)	29,011,920
Palatka	5,765,660	5,765,660	0
Ft. Myers	12,459,712	(7,178,241)	19,637,953
Cape Canaveral	10,830,889	280,346	10,550,543
Riviera	10,226,413	(5,889,945)	16,116,358
Manatee	21,427,179	(2,968,068)	24,395,247
Sanford	16,708,770	(7,621,808)	24,330,578
Turkey Point	12,656,277	(7,716,196)	20,372,473
Martin 1&2	24,108,930	(4,675,983)	28,784,913
Riviera 2		(1,936,013)	1,936,013
Sanford 1&2		(503,486)	503,486
SJRPP	15,572,153	7,804,156	7,767,997
Scherer	6,306,906	(2,884,822)	9,191,728
Total Steam Production	166,326,211	(33,969,374)	200,295,585

Melinda Marzicola **ATTACHMENT B**

	BOOK RESERVE	APPROVED RESERVE ALLOCATIO	RESTATED RESERVE
Other Production			
Ft. Lauderdale	3,672,910	(1,278,840)	4,951,750
Putnam	3,975,193	(2,655,754)	6,630,947
Martin 3 & 4	2,798,907	237,443	2,561,464
Port Everglades GTs	275,618	(156,442)	432,060
Ft. Lauderdale GTs	247,122	(42,017)	289,139
Ft. Myers GTs	1,751,654	(285,841)	2,037,495
Total Other Production	12,721,404	(4,181,451)	16,902,855
Total Dismantlement Provision	179,047,615	(38,150,825)	217,198,440

[*8]

Attachment B

FLORIDA POWER AND LIGHT COMPANY FOSSIL DISMANTLEMENT

	COMMISSION APPROVED ACCRUAL ($)
Steam Production	
Cutler	374,541
Port Everglades	1,688,214
Palatka	
Ft. Myers	1,243,132
Cape Canaveral	641,593
Riviera	853,591
Manatee	1,638,834
Sanford	1,490,155
Turkey Point	1,230,794
Martin 1 & 2	2,029,877
SJRPP	867,729
Scherer	1,155,529
Total Steam Production	13,213,989

	COMMISSION APPROVED ACCRUAL
Other Production	
Ft. Lauderdale	1,044,362
Putnam	442,534
Martin 3 & 4	685,841
Port Everglades GTs	29,961
Ft. Lauderdale GTs	20,347
Ft. Myers GTs	136,981
Total Other Production	2,360,026
Total Dismantlement Provision	15,574,015

FL Public Service Commission Decisions

End of Document

[2002 Fla. PUC LEXIS 284](#)

Florida Public Service Commission

April 11, 2002

DOCKET NO. 001148-EI; DOCKET NO. 020001-EI; ORDER NO. PSC-02-0501-AS-EI, 02 FPSC 4:245

FL Public Service Commission Decisions

Reporter
2002 Fla. PUC LEXIS 284 *

In re: Review of the retail rates of Florida Power & Light Company; In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Disposition: [*1] ORDER APPROVING SETTLEMENT, AUTHORIZING MIDCOURSE CORRECTION, AND REQUIRING RATE REDUCTIONS

Core Terms

base rate, settlement, fuel, refund, retail, cost recovery, customer, annual, cost, beach, revenue sharing, gulf, cap, depreciate, decrease, cents, has, kwh, gross receipts tax, retail customer, was, month, storm, threshold, electric

Panel: The following Commissioners participated in the disposition of this matter: LILA A. JABER, Chairman; J. TERRY DEASON; BRAULIO L. BAEZ; MICHAEL A. PALECKI; RUDOLPH "RUDY" BRADLEY

Opinion

BY THE COMMISSION:

I. <u>CASE BACKGROUND</u>

Docket No. ***001148***-EI was opened on August 15, 2000, to review Florida Power & Light Company's (FPL) proposed merger with Entergy Corporation (Entergy), the formation of a transco, and their effects on FPL's rates and earnings. On April 2, 2001, FPL Group, Inc. announced that the proposed merger with Entergy had been terminated. By Order No. PSC-01-1346-PCO-EI, issued June 19, 2001, in Docket No. ***001148***-EI, FPL was directed to file Minimum Filing Requirements (MFRs) to provide the Commission and all other interested parties the data necessary to begin an evaluation of the level of its earnings. FPL filed its initial set of MFRs on September 17, 2001, with additional filings on October 1, 2001, October 15, 2001, and November 9, 2001. FPL filed testimony on January 18 and 28, 2002. Hearings were scheduled for April 10-12, and 15-16, 2002.

On March 14, 2002, the following **[*2]** documents were filed:

. Joint Motion For Approval Of Stipulation And Settlement

. Stipulation And Settlement

. Florida Power & Light Company's Agreed Motion To Suspend Schedule For Hearings And Prehearing Procedures And To Suspend Discovery (Agreed Motion)

ATTACHMENT B

. Petition Of Florida Power & Light Company For Adjustment to its Fuel Adjustment Factors

FPL's Agreed Motion was granted by Order No. PSC-02-0348-PCO-EI, issued March 14, 2002. By this Order, we approve the Stipulation and Settlement, and the Petition for Adjustment to FPL's Fuel Adjustment Factors. Jurisdiction over these matters is vested in the Commission by various provisions of Chapter 366, Florida Statutes, including Sections 336.04, 366.05, and 366.06, Florida Statutes.

II. STIPULATION AND SETTLEMENT

The Stipulation and Settlement (Stipulation) which is included in this Order as ATTACHMENT 1, and is incorporated herein by reference, is being proffered as a full and complete resolution of all matters pending in Docket No. ***001148***-EI. The Stipulation was signed by all of the parties except for the South Florida Hospital and **[*3]** Healthcare Association. The major elements contained in the Stipulation are as follows:

. $ 250 million permanent base rate reduction effective April 15, 2002 (7.03% base rate reduction) (Paragraph 2)

. Continuation of a revenue cap and a revenue sharing plan for 2002 through 2005 (Paragraph 7)

. Discretionary ability to reduce depreciation expense by up to $ 125 million annually (Paragraph 10)

. Withdrawal of FPL's request to increase the annual Storm Damage Reserve accrual (Paragraph 13)

As part of the Stipulation, FPL has requested a $ 200 million mid-course correction to reduce its fuel cost recovery factors for the remainder of 2002, effective April 15, 2002. That petition is addressed in Section III of this Order.

The Stipulation recites 16 items of agreement among the signatories. Most of the provisions are self-explanatory, but several of the items merit comment or clarification. These are as follows:

PARAGRAPH 2: The $ 250 million annual base rate reduction is an additional reduction over and above the previously implemented $ 350 million annual rate reduction authorized in Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI.

The **[*4]** proposed Stipulation provides for a reduction in base rates of 7.03% for all rate classes except outdoor lighting and street lighting. The Stipulation also provides for a similar reduction in all service charges. It is appropriate to exclude the lighting classes because these classes are already significantly below parity. This allocation methodology differs from FPL's previous rate stipulations that allocated the reduction on a kwh basis. The percentage reduction in base rates is a better method of allocating a decrease because all classes receive the same percentage reduction in base rates. Under an energy allocation, a larger percentage of the total reduction goes to larger commercial and industrial customers relative to residential and small commercial customers.

In Order No. PSC-01-1346-PCO-EI, we stated that one of the reasons for requiring MFRs was to examine the rate relationships among classes. FPL's rate structure has not been formally reviewed since its last rate case in 1983. Since then, new classes have been added and customers have shifted among rate classes seeking more advantageous rates. Based on FPL's cost of service study, there are disparities among the rates **[*5]** of return by class. In a rate case, one of the goals of rate design is to set rates that reflect the costs to serve that class or, stated differently, to set the rate of return for each class equal to the system rate of return. We recognize, however, that a Stipulation is a negotiated document with all participants making some concessions. While the proposed across-the-board percentage reduction does not move FPL's rate structure towards parity, it does not worsen it. Accordingly, we find that the across-the-board reduction is reasonable.

The Stipulation will result in a decrease of $ 5.41 in the total monthly bill of a residential customer who uses 1,000 kilowatt hours, as shown on ATTACHMENT 2, Page 1 of 2. This decrease reflects both the base rate reduction and the fuel adjustment clause mid-course correction approved in Section III of this Order. The rate reductions will become effective for meters read on and after April 15, 2002.

PARAGRAPH 3: Per the terms of this provision, "FPL will no longer have an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels." However, FPL will still have a currently authorized ROE range of 10.00% to 12.00%, **[*6]** with an 11.00% midpoint, for all other purposes, such as cost recovery clauses and Allowance for Funds Used During Construction.

PARAGRAPH 7: Although it is not explicitly stated in the Stipulation, 100% of the retail base rate revenues exceeding the retail base rate revenue cap will be refunded to retail customers on an annual basis.

PARAGRAPH 10: This provision is clarified to indicate that the up to $ 125 million annual credit to depreciation expense is to be on a calendar year basis.

PARAGRAPH 13: FPL is withdrawing its request to increase its Storm Damage Reserve accrual by $ 30 million annually.

PARAGRAPH 15: This provision states that all matters in Docket No. ***001148***-EI are resolved by the Stipulation and Settlement. While the ratemaking aspects of the docket are resolved, there are still issues that may need to be addressed in other forums, such as those related to GridFlorida and to FPL Energy Services.

We have reviewed the terms of the Stipulation, and it appears to be a reasonable resolution of the issues regarding FPL's level of earnings and base rates. The proposed $ 250 million base rate reduction affords FPL's ratepayers significant and immediate relief. **[*7]** The Stipulation also extends the revenue cap and revenue sharing plan through 2005. Since the inception of the existing revenue sharing plan in 1999, FPL has refunded $ 128 million to date and expects to refund an additional $ 84 million for the year ended April 14, 2002. We find that the Stipulation and Settlement is in the best interests of FPL's ratepayers, the parties, and FPL, and is therefore approved.

III. **FPL'S PETITION FOR AN ADJUSTMENT TO ITS FUEL COST RECOVERY FACTORS**

Consistent with the Stipulation, FPL filed a petition in Docket No. 020001-EI seeking to reduce its levelized fuel cost recovery factor to 2.630 cents per kwh, effective April 15, 2002. This will have the effect of reducing the amount collected through the fuel adjustment clause by $ 200 million during the last eight and one half months of 2002.

Absent this $ 200 million reduction, FPL would experience an end-of-period (December 2002) net over-recovery amount of approximately $ 211.2 million based on current projections. This amount represents 8.6% of FPL's total fuel and net power transactions costs as forecasted in its projection testimony in Docket No. 010001-EI. Since FPL filed its projection **[*8]** testimony in Docket No. 010001-EI, its forecasted 2002 fuel cost of system net generation has decreased by $ 193.4 million. This reduction appears to be related primarily to a 12.2% drop in projected natural gas costs and secondarily to a 3.3% drop in retail energy sales.

In the interest of matching fuel revenues with fuel costs, FPL's proposal to refund part of its anticipated over-recovery balance to its ratepayers sooner rather than later is appropriate. Therefore, FPL's Petition for Adjustment to its Fuel Adjustment Factors is granted. The fuel cost recovery factors set forth in Attachment 2, page 2 of 2, which is incorporated herein by reference, shall become effective April 15, 2002. However, we have not yet analyzed the prudence of FPL's actual or projected 2002 fuel costs. The prudence of FPL's 2002 fuel costs will be addressed at the evidentiary hearing scheduled in Docket No. 020001-EI, commencing November 20, 2002.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Settlement and Stipulation filed on March 14, 2002, which is included in this Order as ATTACHMENT 1 and is incorporated by reference herein, is approved. It is further

ORDERED **[*9]** that FPL's Petition for Adjustment to its Fuel Adjustment Factors is granted. It is further

ORDERED that Docket No. ***001148***-EI shall be closed. It is further

ORDERED that Docket No. 020001-EI shall remain open.

By ORDER of the Florida Public Service Commission this 11th day of April, 2002.

BLANCA S. BAYO, Director

Division of the Commission Clerk and Administrative Services

ATTACHMENT 1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Review of the Retail Rates of Florida Power & Light Company

DOCKET NO. ***001148***-EI

STIPULATION AND SETTLEMENT

WHEREAS, the Florida Public Service Commission (FPSC) has initiated a review of retail rates for Florida Power & Light Company (FPL);

WHEREAS, the Office of Public Counsel (OPC), The Florida Industrial Power Users Group (FIPUG), Publix Super Markets, Inc. (Publix), Thomas P. and Genevieve Twomey, Dynegy Midstream Services LP, Florida Retail Federation and Lee County have intervened, and have signed this Stipulation and Settlement;

WHEREAS, FPL has provided the minimum filing requirements (MFRs) as required by the FPSC and such MFRs have been thoroughly reviewed by the FPSC Staff and the Parties to this proceeding;

WHEREAS, **[*10]** FPL has filed comprehensive testimony in support of and detailing its MFRs;

WHEREAS, the parties in this proceeding have conducted extensive discovery on the MFRs and FPL's testimony;

WHEREAS, the Parties to this Stipulation and Settlement have undertaken to resolve the issues raised in this review so as to effect a prompt reduction in base rates charged to customers, to maintain a degree of stability to FPL's base rates and charges, and to provide incentives to FPL to continue to promote efficiency through the term of this Stipulation and Settlement;

WHEREAS, FPL is currently operating under a stipulation and settlement agreement (Current Agreement) agreed to by OPC and other parties, and approved by the FPSC by Order PSC 99-0519-AS-EI;

WHEREAS, the Current Agreement provided for a $ 350 million permanent annual rate reduction for retail customers commencing April 15, 1999 and a revenue sharing plan under which $ 128 million in refunds have been provided to retail customers to date, with $ 84 million in additional refunds projected for the twelve-month period ending April 14, 2002; and

WHEREAS, an extension of revenue sharing through 2005, and an additional permanent rate reduction **[*11]** will further be beneficial to retail customers;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. Upon approval and final order of the FPSC, this Stipulation and Settlement will become effective on April 15, 2002 (the "Implementation Date"), and continue through December 31, 2005.

2. FPL will reduce its base rates by an additional permanent annual amount of $ 250 million. The base rate reduction will be reflected on FPL's customer bills by reducing all base charges for each rate schedule, excluding SL-1 and OL-1, by 7.03%. FPL will begin applying the lower base rate charges required by this Stipulation and Settlement to meter readings made on and after the Implementation Date.

3. Effective on the Implementation Date, FPL will no longer have an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels, and the revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels.

4. For surveillance reporting requirements, FPL's achieved ROE will be calculated based upon an adjusted equity ratio as provided for in the Current Agreement. **[*12]**

5. No party to this Stipulation and Settlement will request, support, or seek to impose a change in the application of any provision hereof. OPC, FIPUG, Publix, Thomas P. and Genevieve Twomey, Dynegy Midstream Services LP, Florida Retail Federation and Lee County will neither seek nor support any additional reduction in FPL's base rates and charges, including interim rate decreases, to take effect prior to the expiration of this Stipulation and Settlement unless such reduction is initiated by FPL. FPL will not petition for an increase in its base rates and charges, including interim rate increases, to take effect before the end of this Stipulation and Settlement, except as provided for in Section 8.

6. During the term of this Stipulation and Settlement, revenues which are above the levels stated herein will be shared between FPL and its retail electric utility customers -- it being expressly understood and agreed that the mechanism for earnings sharing herein established is not intended to be a vehicle for "rate case" type inquiry concerning expenses, investment, and financial results of operations.

7. Commencing on the Implementation Date and for the remainder of 2002 and for calendar **[*13]** years 2003, 2004 and 2005, FPL will be under a Revenue Sharing Incentive Plan as set forth below. For purposes of this Revenue Sharing Incentive Plan, the following retail base rate revenue threshold amounts are established:

I. Revenue Cap - Retail base rate revenues above the retail base rate revenue cap will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2002 will be $ 3,740 million. For 2002 only, the refund to customers will be limited to 71.5% (April 15 through December 31) of the retail base rate revenues exceeding the cap. The retail base rate revenue caps for 2003, 2004 and 2005 will be $ 3,840 million, $ 3,940 million and $ 4,040 million, respectively. Section 9 explains how refunds will be paid to customers.

II. Sharing Threshold - Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap will be divided into two shares on a 1/3, 2/3 basis. FPL's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The sharing threshold for 2002 will be $ 3,580 million in retail base rate revenues. For 2002 only, the refund to the customers will be limited to 71.5% **[*14]** (April 15 through December 31) of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for calendar years 2003, 2004 and 2005 will be $ 3,680 million, $ 3,780 million and $ 3,880 million, respectively. Section 9 explains how refunds will be paid to customers.

8. If FPL's retail base rate earnings fall below a 10% ROE as reported on an FPSC adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of this Stipulation and Settlement, FPL may petition the FPSC to amend its base rates notwithstanding the provisions of Section 5. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding. This Stipulation and Settlement shall terminate upon the effective date of any Final Order issued in such proceeding that changes FPL's base rates.

9. All refunds will be paid with interest at the 30-day commercial paper rate as specified in Rule *25-6.109, Florida Administrative Code*, to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes **[*15]** of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period at the rate of one-twelfth per month. All refunds with interest will be in the form of a credit on the customers' bills beginning with the first day of the first billing cycle of the second month after the end of the applicable refund period. Refunds to former customers will be completed as expeditiously as reasonably possible.

10. In Order No. PSC 99-0519-AS-EI, FPL was authorized to record an amortization amount of up to $ 100 million per year for each of the three years of the settlement agreement which was to be applied to reduce nuclear and/or fossil production plant in service. Under this provision, FPL recorded $ 170,250,000. Starting with the effective

date of this Stipulation and Settlement, FPL may, at its option, amortize up to $ 125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of this Stipulation and Settlement. The amounts so recorded will first go to offset the $ 170,250,000 bottom line amortization amount that has previously been recorded, with any additional **[*16]** amounts recorded to a bottom line negative depreciation reserve during the term of this Stipulation and Settlement. Any such reserve amount will be applied first to reduce any reserve excesses by account, as determined in FPL's depreciation studies filed after the term of this Stipulation and Settlement, and thereafter will result in reserve deficiencies. Any such reserve deficiencies will be allocated to individual reserve balances based on the ratio of the net book value of each plant account to total net book value of all plant. The amounts allocated to the reserves will be included in the remaining life depreciation rate and recovered over the remaining lives of the various assets. Additionally, depreciation rates as addressed in Order Nos. PSC 99-0073-FOF-EI, PSC 00-2434-PAA-EI and PSC 01-1337-PAA-EI will not be changed for the term of this Stipulation and Settlement.

11. Employee dental expenses are considered to be a prudently incurred expense and will be treated as such, including for surveillance reporting, as of the Implementation Date.

12. Additional amortization expense which is being recorded as an offset to the ITC interest synchronization adjustment shall no longer **[*17]** be recorded after the Implementation Date of this Stipulation and Settlement.

13. FPL will withdraw its request for an increase in the annual accrual to the Company's Storm Damage Reserve. In the event that there are insufficient funds in the Storm Damage Reserve and through insurance, FPL may petition the FPSC for recovery of prudently incurred costs not recovered from those sources. The fact that insufficient funds have been accumulated in the Storm Damage Reserve to cover costs associated with a storm event or events shall not be evidence of imprudence or the basis of a disallowance. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding.

14. On April 15, 2002, FPL shall effect a mid-course correction of its Fuel Cost Recovery Clause to reduce the fuel clause factor based on projected over-recoveries, in the amount of $ 200 million, for the remainder of calendar year 2002. The fuel adjustment clause shall continue to operate as normal, including but not limited to, any additional mid-course adjustments that may become necessary and the calculation of true-ups to actual fuel clause expenses. FPL will not use the various cost recovery **[*18]** clauses to recover new capital items which traditionally and historically would be recoverable through base rates.

15. This Stipulation and Settlement is contingent on approval in its entirety by the FPSC. This Stipulation and Settlement will resolve all matters in this Docket pursuant to and in accordance with Section 120.57(4), Florida Statutes (2001). This Docket will be closed effective on the date the FPSC Order approving this Stipulation and Settlement is final.

16. This Stipulation and Settlement dated as of March 12, 2002 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Stipulation and Settlement by their signature.

Florida Power & Light Company

700 Universe Boulevard

Juno Beach, Fl 33408

By: ___

Florida Industrial Power Users Group

McWhirter, Reeves, McGlothlin,

Davidson, Decker, Kaufman,

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By: ___

John W. McWhirter, Jr.

Lee County

Landers and Parsons, P.A.
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Tallahassee, FL 32301

[*19] By: ___

Robert Scheffel Wright

Thomas P. and Genevieve Twomey

Michael Twomey, Esq.
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Florida Retail Federation

Greenberg, Traurig, Hoffman, Lipoff, Rosen & Quentel, P.A.

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By: ___

Ronald C. LaFace

Publix Super Markets, Inc.

Gray, Harris & Robinson, P.A.

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By: ___

Thomas A. Cloud

Dynegy Midstream Services LP

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301 East Pine Street, Suite 1400

Orlando, FL 32801

By: ___

Thomas A. Cloud

ORDER NO. PSC-02-0501-AS-EI

DOCKETS NOS. ***001148***-EI, 020001-EI

ATTACHMENT 2

RESIDENTIAL FUEL COST RECOVERY FACTORS FOR THE PERIOD:

April 15, 2002 - December 2002

NOTE: This schedule reflects a [ILLEGIBLE WORD] correction to Florida Power & Light Company's fuel [ILLEGIBLE WORD] effective April 15, 2002.

			Florida Power & Light Co.
Present (cents per kwh):	January 2002 - April 14, 2002		2,866
Proposed (cents per kwh):	April 15, 2002 - December 2002		2,635
		Increase/Decrease:	-0.231

[*20]

	Florida Power Corporation	**Tampa Electric Company**	**Gulf Power Company**
Present (cents per kwh):	2,692	3,313	2.239
Proposed (cents per kwh):	2.692	3.313	2.239
	0.000	0.000	0.000

	Florida Public Utilities Co. (2)	
	Marianna	**Fernandina Beach**
Present (cents per kwh):	4.060	3.983

	Florida Public Utilities Co. (2)	
	Marianna	**Fernandina Beach**
Proposed (cents per kwh):	4.060	3.983
	-0.000	0.000

TOTAL MONTHLY BILL - RESIDENTIAL SERVICE - 1,000 KILOWATT HOURS

PRESENT	**Florida Power**	**Florida Power**	**Tampa Electric**
January 2002 - April 14, 2002	**& Light Co.**	**Corporation**	**Company**
Base Rate Charges	43.26	49.05	51.92
Fuel and Purchased Power Cost Recuvery Clause	28.66	26.92	33.13
Energy Conservation Cost Recovery Clause	1.87	2.07	1.16
Environmental Cost Recovery Clause	0.00	N/A	1.59
Capacity Cost Recovery Clause	7.01	11.32	3.79
Gross Receipts Tax (1)	0.83	2.29	2.35
Total	$ 81.63	$ 91.65	$ 93.94
PROPOSED	Florida Power	Florida Power	Tampa Electric
April 15, 2002 - December 2002	& Light Co. (3)	Corporation	Company
Base Rate Charges	40.22	49.65	51.92
Fuel and Purchased Power Cost Recovery Clause	26.35	26.92	33.12
Energy Conservation Cost Recovery Clause	1.87	2.07	1.16
Environmental Cost Recovery Clause	0.00	N/A	1.59
Capacity Cost Recovery Clause	7.01	11.32	3.79
Gross Receipts Tax (1)	0.77	2.29	2.35
Total	$ 76.22	$ 91.65	$ 93.94
	Florida Power	Florida Power	Tampa Electric
PROPOSED INCREASE / (DECREASE)	& Light Co.	Corporation	Company
Base Rate Charges	-3.04	0.00	0.00
Fuel and Purchased Power Cost Recovery Clause	-2.31	0.00	0.00
Energy Conservation Cost	0.00	0.00	0.00

PRESENT	**Florida Power**	**Florida Power**	**Tampa Electric**
January 2002 - April 14, 2002	**& Light Co.**	**Corporation**	**Company**
Recovery Clause			
Environmental Cost Recovery Clause	0.00	0.00	0.00
Capacity Cost Recovery Clause	0.00	0.00	0.00
Gross Receipts Tax (1)	-0.06	0.00	0.00
Total	($ 5.41)	$ 0.00	$ 0.00

[*21]

PRESENT	**Gulf Power**	**Florida Public Utilities Co (2)**	
January 2002 - April 14, 2002	**Company**	**Marianna**	**Fernandina Beach**
Base Rate Charges	42.20	20.43	19.20
Fuel and Purchased Power Cost Recuvery Clause	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	0.64	0.83	0.58
Environmental Cost Recovery Clause	1.02	N/A	N/A
Capacity Cost Recovery Clause	0.27	N/A	N/A
Gross Receipts Tax (1)	0.68	1.59	0.61
Total	$ 67.20	$ 63.45	$ 60.22

PROPOSED	Gulf Power	Florida Public Utilities Co. (2)	
April 15, 2002 - December 2002	Company	Marianna	Fernandina Beach
Base Rate Charges	42.20	20.43	19.20
Fuel and Purchased Power Cost Recovery Clause	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	0.61	0.83	0.58
Environmental Cost Recovery Clause	1.02	N/A	N/A
Capacity Cost Recovery Clause	0.27	N/A	N/A
Gross Receipts Tax (1)	0.68	1.59	0.61
Total	$ 67.20	$ 63.45	$ 60.22

	Gulf Power	Florida Public Utilities Co. (2)	
PROPOSED INCREASE / (DECREASE)	Company	Marianna	Fernandina Beach

PRESENT	Gulf Power	Florida Public Utilities Co (2)	
January 2002 - April 14, 2002	Company	Marianna	Fernandina Beach
Base Rate Charges	0.00	0.00	0.00
Fuel and Purchased Power Cost Recovery Clause	0.00	0.00	0.00
Energy Conservation Cost Recovery Clause	0.00	0.00	0.00
Environmental Cost Recovery Clause	0.00	0.00	0.00
Capacity Cost Recovery Clause	0.00	0.00	0.00
Gross Receipts Tax (1)	0.00	0.00	0.00
Total	$ 0.00	$ 0.00	$ 0.00

[*22] (1) Additional gross receipts tax is 1% for Gulf, FPL and FPUC-Fernandina Beach. FPC, TFOO and FPUC-Marianna have removed all GRT from their rates, and thus entire 2.5% is shown separately. (2) Fuel costs include purchased power demand costs of 1.326 for Marianna and 1.888 cents/KWH for Fernandina allocated to the residential class.

(3) Proposed FPL base rate charges reflect reduction resulting from proposed stipulation and settlement In Docket No. ***001148***-EI.

FUEL ADJUSTMENT FACTORS IN CENTS PER KWH BASED ON LINE LOSSES BY RATE GROUP

April 15, 2002 - December 2002

COMPANY	GROUP	RATE SCHEDULES
FP&L	A	RS-1,RST-1,GST-1,GS-LSL-2
	A-1	SL-1,OL-1,PU-1
	B	GSD-1,GSDT-1, CILC-1(O)
	C	GSLD-1,GSLDT-1, CS-1, CST-1
	D	GSLD-2,GSLDT-2, CS-2, CST-2, OS-2, MRT
	E	GSLD-3,GSLDT-3,CS-3,CST-3,CILC-1(T),ISST-1(T)
	F	CILC-1(D),ISST-1(D)
FPC	1	Distribution Secondary Delivery
	2	Distribution Primary Delivery
	3	Transmission Delivery
	4	Lighting Service
TECO	A	RS, RST, GS, GST, TS
	A-1	SL-2,OL-1,3
	B	GSD, GSDT, GSLD, GSLDT, SBF, SBFT
	C	IS-1 & 3, 1ST1 &3, $[ILLEGIBLE WORD] 1 & 3, SBTT1 & 3

COMPANY	GROUP	RATE SCHEDULES
GULF	A	RS,GS,GSD,OS-III,OS-IV, SBS (1CO to 499 kW)
	B	LP. SBS (Contract Demand of 500 to 7499 kW)
	C	PX, PXT, RTP,SBS (Contract Demand above 7499 kW)
	D	OS-LOS-2
FPUC		
Fernandina Beach:	A	RS
	B	GS
	C	GSD
	D	OI, [ILLEGIBLE TEXT], SL-2, SL-3, CSL
	E	GSLD
Marianna:	A	RS
	B	GS
	C	GSD
	D	GLSD
	E	[ILLEGIBLE WORD], OL-2
	F	SL1-2, SL-3

[*23]

REFORE LINE LOSSES

TIME OR USE

COMPANY	GROUP	Standard	On/Peak	Off/Peak
FP&L	A	2,630	2.915	2.501
	A-1	2,568	NA	NA
	B	2.630	2.915	2.502

ATTACHMENT B

REFORE LINE LOSSES

TIME OR USE

COMPANY	GROUP	Standard	On/Peak	Off/Peak
	C	2.630	2.915	2.502
	D	2.630	2.915	2.502
	E	2.630	2.915	2.502
	F	NA	2.915	2.502
FPC	1	2.692	3.273	2.442
	2	2.692	3.273	2.442
	3	2.692	3.273	2.442
	4	2.597	NA	NA
TECO	A	3.301	4.518	2.783
	A-1	3.301	NA	NA
	B	3.301	4.518	2.783
	C	3.301	4.518	2.783
GULF	A	2.212	2.680	2.013
	B	2.212	2.680	2.013
	C	2.212	2.680	2.013
	D	2.182	NA	NA
FPUC				
Fernandina	A	3.983	NA	NA
Beach:	B	3.732	NA	NA
	C	3.581	NA	NA
	D	2.591	NA	NA
	E			
Marianna:	A	4.059	NA	NA
	B	4.042	NA	NA
	C	3.654	NA	NA
	D	3.492	NA	NA
	E	2.529	NA	NA
	F	2.526	NA	NA

FINAL FACTORS

LINE **ADJUSTED FOR LINE LOSSES**

LOSS

COMPANY	**GRO UP**	**MULTIPLIER**	**Standard**
FP&L	A	1.00210	2.635
	A-1	1.00210	2.573
	B	1.00202	2.635
	C	1.00078	2.632
	D	0.99429	2.614
	E	0.95233	2.504
	F	0.99331	NA
FPC	1	1.00000	2.692
	2	0.99000	2.665
	3	0.98000	2.638
	4	1.00000	2.597
TECO	A	1.00350	3.313
	A-1	NA	3.054
	B	1.00090	3.304
	C	0.97920	3.232
GULF	A	1.01228	2.239
	B	0.98106	2.170
	C	0.96230	2.129
	D	1.01228	2.208
FPUC			
Fernandina Beach:	A	1.00000	3.983
	B	1.00000	3.732
	C	1.00000	3.581
	D	1.00000	2.591
	E		
Marianna:	A	1.00000	4.060
	B	1.00000	4.042
	C	1.00000	3.654
	D	1.00000	3.492
	E	1.00000	2.529
	F	1.00000	2.526

[*24]

FINAL FACTORS

ADJUSTED FOR LINE LOSSES

TIME OF USE

COMPANY	GROUP	On/Peak	Off/Peak
FP&L	A	2.921	[ILLEGIBLE TEXT]
	A-1	NA	NA
	B	2.921	2.507
	C	2.917	2.504
	D	2.898	2.487
	E	2.776	2.382
	F	2.895	2.485
FPC	1	[ILLEGIBLE TEXT]	2.442
	2	3.241	2.417
	3	3.208	2.393
	4	NA	NA
TECO	A	4.535	2.793
	A-1	NA	NA
	B	4.523	2.786
	C	4.425	2.725
GULF	A	2.713	2.038
	B	2.629	1.975
	C	2.579	1.938
	D	NA	NA
FPUC			
Fernandina Beach:	A	NA	NA
	B	NA	NA
	C	NA	NA
	D	NA	NA
	E	Actual Fuel Cost plus $ 6.28 per CP kW	
Marianna:	A	NA	NA
	B	NA	NA
	C	NA	NA
	D	NA	NA
	E	NA	NA
	F	NA	NA

Melinda Marzicola **ATTACHMENT B**

End of Document

ATTACHMENT B

2005 Fla. PUC LEXIS 107

Florida Public Service Commission

September 14, 2005, Issued

DOCKET NO. 050045-EI; DOCKET NO. 050188-EI; ORDER NO. PSC-05-0902-S-EI, 05 FPSC 9:32

FL Public Service Commission Decisions

Reporter

2005 Fla. PUC LEXIS 107 *

In re: Petition for rate increase by Florida Power & Light Company; In re: 2005 comprehensive depreciation study by Florida Power & Light Company

Core Terms

settlement, base rate, cost, retail, incremental, customer, calendar year, cap, revenue sharing, depreciate, annual, refund, threshold, has, kwh, was, calculate, target, power plant, gross receipts tax, retail customer, minimum term, growth rate, surcharge, suspend, months, tariff, storm, surveillance, consolidate

Panel: The following Commissioners participated in the disposition of this matter: BRAULIO L. BAEZ, Chairman; J. TERRY DEASON; RUDOLPH "RUDY" BRADLEY; LISA POLAK EDGAR

Opinion

ORDER APPROVING STIPULATION AND SETTLEMENT

BY THE COMMISSION:

I. BACKGROUND

On March 22, 2005, Florida Power & Light Company (FPL) filed a petition for approval of a permanent increase in rates and charges sufficient to generate additional total annual revenues of $ 430,198,000 beginning January 1, 2006, and for approval of an adjustment to 2007 base rates to produce additional annual revenues of $ 122,757,000 beginning 30 days following the commercial in-service date of Turkey Point Unit 5 projected to occur in June 2007. In support of its petition, FPL filed new rate schedules, testimony, Minimum Filing Requirements (MFRs), and other schedules. FPL's petition was assigned Docket No. ***050045***-EI. By Order No. PSC-05-0619-PCO-EI, issued June 6, 2005, we suspended FPL's proposed new rate schedules to allow our staff and intervenors sufficient time to adequately and thoroughly examine the basis for the proposed new rates.

On March 17, 2005, FPL filed a depreciation study for this Commission's review. The depreciation study **[*2]** was assigned Docket No. 050188-EI. By Order No. PSC-05-0499-PCO-EI, issued May 9, 2005, we consolidated Docket Nos. 050188-EI and ***050045***-EI for all purposes.

As part of this consolidated proceeding, we conducted service hearings at the following locations in FPL's service territory: Daytona Beach, Viera, West Palm Beach, Ft. Lauderdale, Miami, Sarasota, and Ft. Myers. A formal administrative hearing was scheduled for August 22 - 26 and August 31 - September 2, 2005. The Office of Public Counsel (OPC), Office of the Attorney General (AG), Florida Industrial Power Users Group (FIPUG), Florida Retail

ATTACHMENT B

Federation (FRF), Commercial Group (CG), AARP, Federal Executive Agencies (FEA), and South Florida Hospital and Healthcare Association (SFHHA) were granted intervenor status. Common Cause Florida and seven individual customers filed a petition to intervene on August 15, 2005.

On August 22, 2005, the parties filed a joint motion for approval of a Stipulation and Settlement [1] among all parties to resolve all matters in this consolidated proceeding. [2] The Stipulation and Settlement was presented at the start of our hearing on August 22. The hearing was recessed to allow our staff to thoroughly **[*3]** review the Stipulation and Settlement and provide its analysis to us on August 24, when the hearing was reconvened for our vote.

By this Order, we approve the Stipulation and Settlement. Jurisdiction over these matters is vested in this Commission by various provisions of Chapter 366, Florida Statutes, including Sections 336.04, *366.05*, and *366.06, Florida Statutes*.

II. STIPULATION AND SETTLEMENT

The major elements contained in the **[*4]** Stipulation and Settlement are as follows:

. The Stipulation and Settlement is effective for a minimum term of four years -- January 1, 2006, through December 31, 2009 -- and thereafter will remain in effect until new base rates and charges become effective by order of the Commission. (Paragraph 1)

. With the exception of certain new and modified rate schedules specified in the Stipulation and Settlement, FPL's retail base rates and charges will remain unchanged on January 1, 2006, when the currently operative stipulation governing FPL's base rates and charges expires. (Paragraph 2)

. No party will petition for a change in FPL's base rates and charges to take effect prior to the minimum term of the Stipulation and Settlement, and, except as provided for in the Stipulation and Settlement, FPL will not petition for any new surcharges to recover costs that traditionally would be, or are presently, recovered through base rates. (Paragraph 3)

. A revenue sharing plan similar to the one contained in FPL's currently operative rate settlement will be implemented through the term of the Stipulation and Settlement. Retail base rate revenues between specified sharing threshold amounts **[*5]** and revenue caps will be shared as follows: FPL's shareholders will receive a 1/3 share, and FPL's retail customers will receive a 2/3 share. Retail base rate revenues above the specified revenue caps will be refunded to retail customers on an annual basis. (Paragraphs 4 and 5)

. If FPL's retail base rate earnings fall below a 10% ROE as reported on a Commission-adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of the Stipulation and Settlement, FPL may petition to amend its base rates, and parties to the Stipulation are not precluded from participating in such a proceeding. This provision does not limit FPL from any recovery of costs otherwise contemplated by the Stipulation. (Paragraph 6)

. FPL has the option to amortize up to $ 125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement. (Paragraph **[*6]** 8)

. Subject to review for prudence and reasonableness, FPL is permitted clause recovery of incremental costs associated with establishment of a Regional Transmission Organization or costs arising from an order of this

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[1] The Stipulation and Settlement is attached hereto as Attachment A and is incorporated herein by reference.

[2] Although Common Cause Florida and the individual customers had not been granted intervenor status, they signed the stipulation and settlement along with all parties. Under these circumstances and without objection from any party, we found at the August 22 hearing that it was not necessary to make a ruling on the petition to intervene filed by Common Cause Florida and the individual customers.

Commission or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. (Paragraph 9)

. No party will appeal the Commission's final order in Docket No. 041291-EI addressing recovery of 2004 storm recovery costs. FPL will suspend its current accrual to its storm reserve effective January 1, 2006. Through a separate proceeding, a target level for FPL's storm reserve will be set. Replenishment of the storm reserve to that target level shall be accomplished through securitization under *Section 366.8260, Florida Statutes*, or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. (Paragraph 10)

. FPL will suspend its current nuclear decommissioning accrual effective September 1, 2005, and at least through the minimum term of the Stipulation and Settlement. (Paragraph **[*7]** 11)

. New capital costs for expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, on a demand basis. (Paragraph 13)

. All post-September 11, 2001, incremental security costs will be recovered through the Capacity Cost Recovery Clause. (Paragraph 14)

. FPL will continue to operate without an authorized ROE range for the purpose of addressing earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes. (Paragraph 16)

. For any power plant that is approved through the Power Plant Siting Act and that achieves commercial operation within the term of the Stipulation and Settlement, the costs of which are not recovered fully through a clause or clauses, FPL's base rates will increase by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements were or are predicated and pursuant to which a need determination was granted by the Commission. This base rate adjustment will be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits by an equal percentage **[*8]** and will apply to meter readings made on and after the commercial in-service date of the plant. (Paragraph 17)

Most of the terms of the Stipulation and Settlement appear to be self-explanatory. Still, we believe that several provisions merit comment or clarification so that as full an understanding of the parties' intent can be reflected in this Order before the Stipulation and Settlement is implemented. Based on the parties' discussions with our staff and discussions during our August 24 vote to approve the Stipulation and Settlement, we understand that the parties agree with the clarifications discussed below.

Paragraph 2

Under Paragraph 2, the parties agree that FPL will implement three new tariff offerings: an optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor breakeven point by class; a Seasonal Demand Time-of-Use rate; and a General Service Constant Use rate. Further, the parties agree that FPL will eliminate the 10 kW exemption from its current rate schedules. We note that these changes are revenue neutral across FPL's demand-metered rate classes but are not revenue neutral within each such class.

Further, the parties agree that **[*9]** the inversion point on FPL's RS-1 (residential service) rate will be raised from 750 kWh to 1,000 kWh. We note that this change is revenue neutral within FPL's residential rate class.

The parties also agree that all gross receipts taxes will be shown as and collected through a separate gross receipts tax line item on bills. Thus, the portion of gross receipts taxes currently embedded in base rates will be removed and consolidated with the portion of gross receipts taxes currently shown separately.

Paragraph 5

Paragraph 5 describes and defines the revenue sharing plan agreed to by the parties. Part c of this paragraph states that the revenue sharing plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues based on FPL's current structure and regulatory framework.

Further, part c indicates that incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates will be excluded in determining retail base rate revenues for purposes of the revenue sharing plan. The parties clarified that in the event that a portion of FPL's system is sold or municipalized, appropriate **[*10]** adjustments would be made to account for the associated revenue reduction before application of FPL's annual average growth rate upon which the revenue sharing thresholds and revenue cap are calculated.

Paragraph 10

Under Paragraph 10, the parties agree that FPL will suspend its current base rate accrual of $ 20.3 million to its storm reserve account effective January 1, 2006. Further, the parties agree that a target for FPL's storm reserve account will be established in a separate proceeding and that funding the account to the target level will be achieved by either or both of two means: (1) a separate surcharge independent of and incremental to retail base rates; and (2) through the recently enacted provisions of *Section 366.8260, Florida Statutes*. FPL has committed to pursue continued funding of its storm reserve account within six months.

Paragraph 11

Pursuant to Paragraph 11, the parties agree that FPL will file a nuclear decommissioning study on or before December 12, 2005, but the study shall have no impact on FPL's base rates or charges or the terms of the Stipulation and Settlement. The parties clarified that the filing of **[*11]** this study is intended only for informational purposes and that no Commission action on the study is contemplated.

Paragraph 13

We note that Paragraph 13 reflects a change in practice with respect to the allocation of capital costs recovered through the Environmental Cost Recovery Clause (ECRC). These costs historically have been allocated to customer classes on an energy basis. Under the Stipulation and Settlement, the parties agree that new capital costs for environmental expenditures recovered through the ECRC will be allocated on a demand basis instead, consistent with the treatment of capital costs in a base rate cost of service study.

Paragraph 14

Currently, post-September 11, 2001, incremental security costs related only to power plant security are recovered through the Capacity Cost Recovery Clause (Capacity Clause). Pursuant to Paragraph 14, all post-September 11, 2001, incremental security costs -- both power plant and non-plant security costs -- will be recovered through the Capacity Clause.

Paragraph 17

The parties clarified that in the event the actual capital cost of a generation project subject to Paragraph 17 is lower than the projected cost, the difference **[*12]** will be reflected as a one-time credit through the Capacity Clause.

Other Matters

Pursuant to a stipulation approved in Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, FPL currently recovers incremental hedging costs through the Fuel Cost Recovery Clause (Fuel Clause). In its petition for a rate increase, FPL proposed to recover these costs through base rates instead. The Stipulation and Settlement is silent on how incremental hedging costs will be recovered. The parties clarified that they intended for recovery of these costs to continue through the Fuel Clause during the term of the Stipulation and Settlement. Because the Stipulation is silent in this regard, the parties indicated that they would take action to memorialize their intent in this year's Fuel Clause proceedings.

The parties also clarified their intent that, upon approval of this Stipulation and Settlement, Docket No. 050494-EI should be closed. Docket No. 050494-EI was assigned to a joint petition for a decrease in FPL's base rates and charges filed July 19, 2005, by several of the intervenors in this docket.

ATTACHMENT B

III. FINDINGS

Upon review and consideration, we find that the Stipulation **[*13]** and Settlement provides a reasonable resolution of the issues in this proceeding with respect to FPL's rates and charges and its depreciation rates and capital recovery schedules. The Stipulation and Settlement appears to provide FPL's customers with a degree of stability and predictability with respect to their electricity rates while allowing FPL to maintain the financial strength to make investments necessary to provide customers with safe and reliable power. Further, the Stipulation and Settlement extends through 2009 a revenue sharing plan which, since its inception in 1999, has resulted in refunds to customers of over $ 225 million to date. In addition, we recognize that the Stipulation and Settlement reflects the agreement of a broad range of interests: FPL, OPC, the Attorney General, and residential, commercial, industrial, and governmental customers of FPL.

In conclusion, we find that the Stipulation and Settlement establishes rates that are fair, just, and reasonable and that approval of the Stipulation and Settlement is in the public interest. Therefore, we approve the Stipulation and Settlement. As with any settlement we approve, nothing in our approval of this Stipulation **[*14]** and Settlement diminishes this Commission's ongoing authority and obligation to ensure fair, just, and reasonable rates. Nonetheless, this Commission has a long history of encouraging settlements, giving great weight and deference to settlements, and enforcing them in the spirit in which they were reached by the parties.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Stipulation and Settlement filed August 22, 2005, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that FPL shall file, for administrative approval, revised tariff sheets to reflect the terms of the Stipulation and Settlement. It is further

ORDERED that Docket Nos. ***050045***-EI, 050188-EI, and 050494-EI shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of September, 2005.

By:

Kay Flynn, Chief

Bureau of Records

ATTACHMENT A

In re: Petition for rate increase by Florida Power & Light Company

In re: 2005 comprehensive depreciation study by Florida Power & Light Company

DOCKET NO. ***050045***-EI

DOCKET NO. 050188-EI

STIPULATION AND SETTLEMENT

WHEREAS, pursuant to its petition **[*15]** filed March 22, 2005, Florida Power & Light Company (FPL) has petitioned the Florida Public Service Commission (FPSC or Commission) for an increase in base rates and other related relief;

WHEREAS, the Office of the Attorney General (AG), the Office of Public Counsel (OPC), The Florida Industrial Power Users Group (FIPUG), AARP, Florida Retail Federation (FRF), the Commercial Group (CG), the Federal Executive Agencies (FEA), and South Florida Hospital and Healthcare Association (SFHHA) have intervened, and have signed this Stipulation and Settlement (unless the context clearly requires otherwise, the term Party or Parties means a signatory to this Stipulation and Settlement) ;

WHEREAS, FPL and the Parties to this Stipulation and Settlement recognize that this is a period of unprecedented world energy prices and that this Stipulation and Settlement will mitigate the impact of high energy prices;

WHEREAS, FPL has provided the minimum filing requirements (MFRs) as required by the FPSC and such MFRs have been thoroughly reviewed by the FPSC Staff and the Parties to this proceeding;

WHEREAS, FPL has filed comprehensive testimony in support of and detailing its MFRs;

WHEREAS, on March 16, **[*16]** 2005, FPL filed comprehensive depreciation studies in accordance with FPSC Rule *25-6.0436(8)(a), Florida Administrative Code*;

WHEREAS, the parties in this proceeding have conducted extensive discovery on the MFRs, depreciation studies, and FPL's testimony;

WHEREAS, the discovery conducted has included the production and opportunity to inspect more than 315,000 pages of information regarding FPL's costs and operations;

WHEREAS, the Parties to this Stipulation and Settlement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability to FPL's base rates and charges, and to provide incentives to FPL to continue to promote efficiency through the term of this Stipulation and Settlement;

WHEREAS, FPL is currently operating under a stipulation and settlement agreement agreed to by OPC and other parties, and approved by the FPSC by Order PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI and 020001-EI (2002 Agreement);

WHEREAS, previous to the 2002 Agreement, FPL operated under a stipulation and settlement agreement approved by the FPSC in Order No. PSC 99-0519-AS-EI (1999 Agreement); **[*17]**

WHEREAS, the 1999 and 2002 Agreements, combined, provided for a reduction of $ 600 million in FPL's base rates, and include revenue sharing plans that have resulted in refunds to customers to date in excess of $ 225 million;

WHEREAS, the 1999 and 2002 Agreements and revenue sharing plans have provided significant benefits to customers, resulting in approximately $ 4 billion in total savings to FPL's customers through the end of 2005;

WHEREAS, during 2005 FPL has added two new power plants in Martin and Manatee Counties at installed costs totaling approximately $ 887 million without increasing base rates;

WHEREAS, FPL must make substantial investments in the construction of new electric generation and other infrastructure for the foreseeable future in order to continue to provide safe and reliable power to meet the growing needs of retail customers in the state of Florida; and

WHEREAS, an extension of the revenue sharing plan and preservation of the benefits for customers of the $ 600 million reduction in base rates provided for in the 1999 and 2002 Agreements during the period in which this Stipulation and Settlement is in effect, and other provisions as set forth herein, including **[*18]** the provision for the incremental base rate recovery of costs associated with the addition of electric generation, will further be beneficial to retail customers;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. Upon approval and final order of the FPSC, this Stipulation and Settlement will become effective on January 1, 2006 (the "Implementation Date"), and shall continue through December 31, 2009 (the "Minimum Term"), and

thereafter shall remain in effect until terminated on the date that new base rates become effective pursuant to order of the FPSC following a formal administrative hearing held either on the FPSC's own motion or on request made by any of the Parties to this Stipulation and Settlement in accordance with Chapter 366, Florida Statutes.

2. FPL's retail base rates and base rate structure shall remain unchanged, except as otherwise permitted in this Stipulation and Settlement. The following tariff changes shall be approved and implemented:

a. (i) As reflected in FPL's MFR E-14, institution of the optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor **[*19]** breakeven point by rate class, the Seasonal Demand Time-of-Use rate, and the General Service Constant Use Rate;

(ii) Elimination of the 10 kW exemption from rates.

(iii) The combined adjustments to implement (i) and (ii) above shall be made on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

b. Raising the inversion point on the RS-1 rate from 750 kWh to 1,000 kWh, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

c. Consolidation and collection of all gross receipts taxes, including existing gross receipts taxes embedded in base rates, through the separate gross receipts tax line item on bills, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

d. At any time during the term of the Stipulation and Settlement and subject to Commission approval, any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of the Stipulation and Settlement unless the application **[*20]** of such new or revised tariff or rate schedule is optional to the utility's customers.

3. Except as provided in Section 1, no Party to this Stipulation and Settlement will request, support, or seek to impose a change in the application of any provision hereof. AG, OPC, FIPUG, AARP, FRF, FEA, CG, and SFHHA will neither seek nor support any reduction in FPL's base rates and charges, including interim rate decreases, to take effect prior to the end of the Minimum Term of this Stipulation and Settlement unless a reduction request is initiated by FPL. FPL will not petition for an increase in its base rates and charges, including interim rate increases, to take effect for meter readings before the end of the Minimum Term except as provided for in Section 6. During the term of this Stipulation and Settlement, except as otherwise provided for in this Stipulation and Settlement, or except for unforeseen extraordinary costs imposed by government agencies relating to safety or matters of national security, FPL will not petition for any new surcharges, on an interim or permanent basis, to recover costs that are of a type that traditionally and historically would be, or are presently, recovered **[*21]** through base rates.

4. During the term of this Stipulation and Settlement, revenues which are above the levels stated herein below in Section 5 will be shared between FPL and its retail electric utility customers -- it being expressly understood and agreed that the mechanism for earnings sharing herein established is not intended to be a vehicle for "rate case" type inquiry concerning expenses, investment, and financial results of operations.

5. Commencing on the Implementation Date and for the calendar years 2006, 2007, 2008 and 2009, and continuing thereafter until terminated, FPL will be under a Revenue Sharing Incentive Plan as set forth below. For purposes of this Revenue Sharing Incentive Plan, the following retail base rate revenue threshold amounts are established:

a. Sharing Threshold -- Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap as defined in Section 5(b) below will be divided into two shares on a 1/3, 2/3 basis. FPL's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The sharing threshold for 2006 will be established by using the 2005 sharing threshold of $ 3,880 million **[*22]** in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten year period ending December 31, 2005. For each succeeding calendar year or portion thereof during which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue sharing threshold amounts shall be established by increasing the prior year's threshold by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue sharing threshold and (ii) the amount of any incremental GBRA revenues in that year. The GBRA is described in Section 17.

b. Revenue Cap -- Retail base rate revenues above the retail base rate revenue cap will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2006 will be established by using the 2005 cap of $ 4,040 million in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31, 2005. For each succeeding calendar year or portion thereof during **[*23]** which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue cap amounts shall be established by increasing the prior year's cap by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue cap amount and (ii) the amount of any incremental GBRA revenues in that year.

c. Revenue exclusions -- The Revenue Sharing Incentive Plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues of FPL based on its current structure and regulatory framework. Thus, for example, incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates, whether inside or outside the state of Florida, or revenues from any clause, surcharge or other recovery mechanism other than retail base rates, shall be excluded in determining retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

d. Refund mechanism -- Refunds will be paid to customers as **[*24]** described in Section 7.

e. Calculation of sharing threshold and revenue cap for partial calendar years -- In the event that this Stipulation and Settlement is terminated other than at the end of a calendar year, the sharing threshold and revenue cap for the partial calendar year shall be determined at the end of that calendar year by (i) dividing the retail kWh sales during the partial calendar year by the retail kWh for the full calendar year, and (ii) applying the resulting fraction to the sharing threshold and revenue cap for the full calendar year that would have been calculated as set forth in Sections 5(a) and 5(b) above.

f. Calculation of annual average growth rate -- For purposes of this Section 5, the average annual growth rate shall be calculated by summing the percentage change in retail kWh sales for each year in the relevant ten year period and dividing by 10.

6. If FPL's retail base rate earnings fall below a 10% ROE as reported on an FPSC adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of this Stipulation and Settlement, FPL may petition the FPSC to amend its base rates notwithstanding the provisions of Section 3, either as **[*25]** a general rate proceeding or as a limited proceeding under *Section 366.076, Florida Statutes*. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding, and, in the event that FPL petitions to initiate a limited proceeding under this Section 6, any Party may petition to initiate any proceeding otherwise permitted by Florida law. This Stipulation and Settlement shall terminate upon the effective date of any Final Order issued in such proceeding that changes FPL's base rates. This paragraph shall not be construed to bar or limit FPL from any recovery of costs otherwise contemplated by this Stipulation and Settlement.

7. All revenue-sharing refunds will be paid with interest at the 30-day commercial paper rate to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period. All refunds with interest will be in the form of a credit on the customers' **[*26]** bills beginning with the first day of the first billing cycle of the second month after the end of the applicable refund period (or, in the case of a partial calendar year refund, after the end of that calendar year) . Refunds to former customers will be completed as expeditiously as reasonably possible.

8. Starting with the effective date of this Stipulation and Settlement, FPL may, at its option, amortize up to $ 125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of this Stipulation and Settlement. Any such reserve amount will be applied first to reduce any reserve

excesses by account, as determined in FPL's depreciation studies filed after the term of this Stipulation and Settlement, and thereafter will result in reserve deficiencies. Any such reserve deficiencies will be allocated to individual reserve balances based on the ratio of the net book value of each plant account to total net book value of all plant. The amounts allocated to the reserves will be included in the remaining life depreciation rate and recovered over the remaining lives of the various assets. Additionally, depreciation rates and/or capital **[*27]** recovery schedules shall be established pursuant to the comprehensive depreciation studies as filed March 16, 2005 and will not be changed for the term of this Stipulation and Settlement.

9. FPL will be permitted clause recovery of prudently incurred incremental costs associated with the establishment of a Regional Transmission Organization or any other costs arising from an order of the FPSC or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. Any Party to this Stipulation and Settlement may participate in any proceeding relating to the recovery of costs contemplated in this section for the purpose of challenging the reasonableness and prudence of such costs, but not for the purpose of challenging FPL's right to clause recovery of such costs.

10. No Party to this Stipulation and Settlement shall appeal the FPSC's Final Order in Docket No. 041291-EI. Further, Parties agree to the following provisions relative to the target level and funding of Account No. 228.1 and recovery of any deficits in such Account:

a. The target level for Account No. 228.1 shall be as established **[*28]** by the Commission, whether on its own motion, upon petition by FPL, or in conjunction with a proceeding held in accordance with *Section 366.8260, Florida Statutes*. FPL will be permitted to recover prudently incurred costs associated with events covered by Account No. 228.1 and replenish Account No. 228.1 to a target level through charges to customers, that are approved by the Commission, that are independent of and incremental to base rates and without the application of any form of earnings test or measure. The fact that insufficient funds have been accumulated in Account No. 228.1 to cover costs associated with events covered by that Account shall not be evidence of imprudence or the basis of a disallowance. Replenishment of Account No. 228.1 to a target level approved by the Commission and/or the recovery of any costs incurred in excess of funds accumulated in Account No. 228.1 and insurance shall be accomplished through *Section 366.8260, Florida Statutes*, and/or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. Parties to this **[*29]** Stipulation and Settlement are not precluded from participating in such a proceeding, nor precluded from challenging the amount of such target level or whether recovery should be accomplished either through *Section 366.8260, Florida Statutes* or through a separate surcharge.

b. The current base rate accrual to Account No. 228.1 of $ 20.3 million is suspended effective January 1, 2006.

c. No revenues contemplated by this Section 10 shall be included in the computation of retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

11. The current decommissioning accrual of $ 78,516,937 (jurisdictional) approved in Order No. PSC-02-0055-PAA-EI shall be suspended effective September 1, 2005 and shall remain suspended through the Minimum Term and, at the Company's option, for any additional period during which this Stipulation and Settlement remains in effect. FPL's decommissioning study to be filed on or before December 31, 2005 shall have no impact on FPL's base rates, charges, or the terms of this Stipulation and Settlement.

12. The portion of St. Johns River Power Park ("SJRPP") capacity costs and certain **[*30]** capacity revenues that are currently embedded in base rates shall continue to be recovered through base rates in the current manner as contemplated by Order No. PSC-92-1334-FOF-EI.

13. New capital costs for environmental expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, consistent with FPL's current cost of service methodology.

14. Post-September 11, 2001 incremental security costs shall remain in and be recovered through the Capacity Clause.

15. For surveillance reporting requirements and all regulatory purposes, FPL's ROE will be calculated based upon an adjusted equity ratio as follows. FPL's adjusted equity ratio will be capped at 55.83% as included in FPL's projected 1998 Rate of Return Report for surveillance purposes. The adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology.

16. Effective on the Implementation Date, FPL will continue to operate without an authorized Return on Equity (ROE) range for the purpose of **[*31]** addressing earnings levels, and the revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes.

17. For any power plant that is approved pursuant to the Florida Power Plant Siting Act (PPSA) and achieves commercial operation within the term of this Stipulation and Settlement, the costs of which are not recovered fully through a clause or clauses, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements (CPVRR) were or are predicated, and pursuant to which a need determination was granted by the FPSC, such adjustment to be reflected on FPL's customer bills by increasing base charges, and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date of any such power plant. Such adjustment shall be referred to as a Generation Base Rate Adjustment (GBRA). The **[*32]** GBRA will be calculated using an 11.75% ROE and the capital structure as per Section 15 above. FPL will calculate and submit for Commission confirmation the amount of the GBRA using the Capacity Clause projection filing for the year that the plant is to go into service. In the event that the actual capital costs of generation projects are lower than were or are projected in the need determination proceeding, the difference will be flowed back via a true-up to the Capacity Clause. In the event that actual capital costs for such power plant are higher than were projected in the need determination proceeding, FPL at its option may initiate a limited proceeding per *Section 366.076, Florida Statutes*, limited to the issue of whether FPL has met the requirements of Rule *25-22.082(15), Florida Administrative Code*. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), FPL shall increase the GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking **[*33]** any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Upon termination of the Stipulation and Settlement, FPL's base rate levels, including the effects of any GBRA, shall continue in effect until next reset by the Commission. Any Party to this Stipulation and Settlement may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15). A GBRA shall be implemented upon commercial operation of Turkey Point Unit 5, currently projected to occur in mid-2007, by increasing base rates by the estimated annual revenue requirement exclusive of fuel of the costs upon which the CPVRR for Turkey Point Unit 5 were predicated, and pursuant to which a need determination was granted by the FPSC in Order No. PSC-04-0609-FOF-EI, such adjustment to be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date **[*34]** of Turkey Point Unit 5.

18. This Stipulation and Settlement is contingent on approval in its entirety by the FPSC. This Stipulation and Settlement will resolve all matters in these Dockets pursuant to and in accordance with *Section 120.57(4), Florida Statutes*. This Docket will be closed effective on the date the FPSC Order approving this Stipulation and Settlement is final.

19. All Parties to this Stipulation and Settlement agree to endorse and support the Stipulation and Settlement before the FPSC and any other administrative or judicial tribunal, and in any other forum.

20. This Stipulation and Settlement dated as of August 22, 2005 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Stipulation and Settlement by their signature.

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ATTACHMENT B

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 080677-EI
In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.	DOCKET NO. 090130-EI ORDER NO. PSC-10-0153-FOF-EI ISSUED: March 17, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. WADE LITCHFIELD, MITCHELL S. ROSS, JOHN T. BUTLER, BRYAN S. ANDERSON, and JESSICA A. CANO, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420; and
SUSAN F. CLARK., Radey Thomas Yon & Clark, P.A., 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301
On behalf of FLORIDA POWER & LIGHT COMPANY (FPL).

JOSEPH A. McGLOTHLIN, CHARLIE BECK, PATRICIA A. CHRISTENSEN, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
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On behalf of the FLORIDA ASSOCIATION FOR FAIRNESS IN RATE MAKING (AFFIRM)

CECILIA BRADLEY, Office of the Attorney General, The Capitol – PL01, Tallahassee, FL 32399
On behalf of the ATTORNEY GENERAL FOR THE CITIZENS OF FLORIDA (AG)

ATTACHMENT B

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On behalf of ASSOCIATED INDUSTRIES OF FLORIDA (AIF)

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On behalf of the CITY OF SOUTH DAYTONA (CSD)

CAPTAIN SHAYLA L. MCNEILL, AFLOA/JACL-ULT, AFCESA, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, Florida 32403
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On behalf of the Florida Retail Federation (FRF)

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On behalf of the South Florida Hospital and Healthcare Association (SFHHA)

D. MARCUS BRASWELL, JR., ESQUIRE AND ROBERT A SUGARMAN, ESQUIRE, 100 Miracle Mile, Suite 300, Coral Gables, FL 33134
On behalf of IBEW System-Council U-4 (SCU-4)

STEPHEN STEWART Post Office Box 12878, Tallahassee, Florida 32317
On behalf of Mr. Richard Unger (UNGER)

LISA C. BENNETT, MARTHA CARTER BROWN, JEAN HARTMAN, ANNA WILLIAMS, KEINO YOUNG, and KATHRYN COWDERY, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (STAFF).

MARY ANNE HELTON, Deputy General Counsel, SAMANTHA CIBULA, ADAM TEITZMAN, and JENNIFER BRUBAKER, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisors to the Florida Public Service Commission.

ORDER DENYING IN PART, AND GRANTING IN PART, FLORIDA POWER & LIGHT COMPANY'S REQUEST FOR A PERMANENT RATE INCREASE AND SETTING DEPRECIATION AND DISMANTLEMENT RATES AND SCHEDULES

BY THE COMMISSION:

BACKGROUND

This proceeding commenced on March 18, 2009, with the filing of a petition for a permanent rate increase by Florida Power & Light Company (FPL or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. FPL provides electric service to approximately 4.5 million retail customers in all or parts of 35 Florida counties.

FPL requested an increase in its retail rates and charges to generate $1.044 billion in additional gross annual revenues, effective January 4, 2010. If granted, this increase would have allowed the Company to earn an overall rate of return of 8.00 percent or a 12.50 percent return on equity, with a range of 11.50 percent to 13.50 percent. The Company based its request on a projected test year ending December 31, 2010. FPL also requested a $247.4 million subsequent year base rate increase effective January 2011. This additional increase would have allowed the Company to earn an overall rate of return of 8.18 percent or a 12.50 percent return on equity (range 11.50 percent to 13.50 percent). The Company based its subsequent year request on a projected test year ending December 31, 2011. In addition to its 2010 and 2011 rate increases, FPL requested approval of a Generation Base Rate Adjustment (GBRA) mechanism that would allow FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time the plants enter commercial service. FPL did not request any interim rate relief. Order No. PSC-09-0351-PCO-EI, issued May 22, 2009, in this docket, suspended the proposed final rates.

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The Office of Public Counsel (OPC), the Office of the Attorney General (AG), the Florida Industrial Power Users Group (FIPUG), The Florida Retail Federation (FRF), the Florida Association for Fairness in Rate Making (AFFIRM), the Federal Executive Agencies (FEA), the South Florida Hospital and Healthcare Association (SFHHA), the Associated Industries of Florida (AIF), the City of South Daytona, Florida (South Daytona), the I.B.E.W. System Council U-4 (SCU-4), the FPL Employee Intervenors (Employee Intervenors), and Richard Unger (Unger) intervened in this proceeding. OPC, AG, FIPUG, FRF, AFFIRM, FEA, SFHHA, South Daytona and Mr. Unger objected to FPL's petition for rate increase. OPC, FIPUG, and SFHHA filed testimony supporting a rate decrease.

Pursuant to Florida Statutes, we conducted 9 customer service hearings at the following locations and dates: Sarasota and Ft. Myers, June 19, 2009; Daytona Beach, June 23, 2009; Melbourne and West Palm Beach, June 24, 2009; Ft. Lauderdale and Miami, June 25, 2009; and Miami Gardens and Plantation, June 26, 2009. The Technical Hearing was held in Tallahassee on August 24-28 and 31, 2009, September 2-5, 16 and 17, 2009, and October 21-23, 2009. During the hearing, we approved several stipulated issues, which are reflected in Appendix A to this Order.

On January 13, 2010, at a Special Agenda Conference, we considered the revenue requirements and rate design for FPL. At a January 29, 2010, Special Agenda Conference, we considered the rates to be charged to FPL's customers. This Order reflects our decisions in these dockets. We have jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.041, 366.06, 366.07, and 366.076, F.S.

2010 PROPOSED TEST PERIOD

Legal authority to approve base rate increase

The parties requested that we rule on whether we had the legal authority to use a projected test year in setting rates. In 1983, the Florida Supreme Court, in a telecommunications case, settled that question:

> Section 364.035(1), Florida Statutes (1981) [telecommunications], provides that the Commission has the authority to fix "just, reasonable, and compensatory rates." Nothing in the decisions of this Court or any legislative act prohibits the use of a projected test year by the Commission in setting a utility's rates. We agree with the Commission that it may allow the use of a projected test year as an accounting mechanism to minimize regulatory lag. The projected test period established by the Commission is a ratemaking tool which allows the Commission to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility.

Southern Bell Tel. & Tel. Co. v. Public Service Commission, 443 So. 2d 92, 97 (Fla. 1983) (Southern Bell). As we had the authority in telecommunications to use a projected test year, so also do we have the authority to fix "just, reasonable, and compensatory rates" for investor-owned electric utilities. See Section 366.041(1), F.S. A comparison of Section 364.035(1) to

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366.041(1), F.S., reveals virtually identical language for the two different industries. In 1985, in an investor-owned electric utility case, the Florida Supreme Court acknowledged our inherent authority to combat regulatory lag by considering and recognizing factors which affect future rates and to grant rate increases based on those factors. Floridians United for Safe Energy, Inc. v. Public Service Commission, 475 So. 2d 241, 242 (Fla. 1985) (Floridians United).

By adopting Rule 25-6.140, Florida Administrative Code (F.A.C.), we codified the Supreme Court's decisions in Southern Bell and Floridians United by requiring an investor-owned electric utility to give an explanation for the test year if the utility chooses to select a projected test year. We have on numerous occasions over the past 20 years used the projected test year method of accounting to set rates for electric utilities. Accordingly, we determine that we have the legal authority to approve a base rate increase using a 2010 projected test year.

Projected Test Period

FPL proposed to utilize a fully projected 2010 test year as the basis for its overall jurisdictional revenue requirement calculation. Generally, the periods covered in FPL's Minimum Filing Requirements (MFRs) in support of its application were the 2008 historical year, 2009 Prior Year, and 2010 Test Year. FPL filed its MFRs based upon forecasts completed in late 2008. The accuracy of FPL's 2010 forecasts is discussed more extensively in our consideration of forecasts of customers, below.

As we have acknowledged in prior dockets, there are primarily two options we may use in evaluating a utility's rate case. The two options are the historic test year and the projected test year. Both options have strengths and weaknesses. In determining to use the projected test year for Gulf[1] in its 2001 rate request, we stated:

> The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.
>
> The main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the Company's ability to use the forecast for setting rates.

In granting Gulf's request for the use of the projected test year, we acknowledged that extensive discovery was conducted on the forecasts, and, with adjustments, was appropriate.

In this docket, we find that the projected test year of the twelve months ended December 31, 2010, provides the best opportunity for a proper matching of revenues, expenses, and rate

[1] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.

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base investment for 2010. Accordingly, we accept FPL's proposed 2010 year proposed, with the adjustments discussed below.

Forecasts of customers

FPL's 2010 forecast of customers, kilowatt hours (kWh), and kilowatts (kW) by rate class are consistent with the sales and customer forecast by revenue class and reflect the particular billing determinants specified in each rate schedule if certain adjustments are made to the forecast. Both FPL and OPC suggested changes to FPL's load forecast.

FPL's 2010 forecast of customers, kWh, and kW was sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser. The two primary elements of FPL's projections were its forecasts of the total number of customers and the Net Energy for Load (NEL). FPL forecasted the total number of customers with an econometric model using population and seasonal factors as explanatory variables. FPL forecasted NEL per customer with an econometric model based upon the level of economic activity, weather, and the price of electricity. NEL was then projected by multiplying the customer forecasts by the NEL per customer forecasts. FPL relied upon independent sources for its forecast assumptions such as the University of Florida's Bureau of Economic and Business Research (BEBR) for its population projections, and Global Insight, Moody's Economy.com, and the Florida Legislature for its economic projections.

These aggregate forecasts were then broken down into separate revenue class forecasts (e.g. Residential, Commercial, Industrial, etc.) for the number of customers and kWh sales by revenue class. These projections were ultimately used to determine the level of test year revenues FPL would earn in 2010 under its current rates and, together with the Company's revenue requirement for 2010, determine the amount of rate relief FPL was requesting in its petition.

FPL's forecast was prepared in late 2008 and used historical monthly data from 1990 through October 2008 for its customer forecast, and historical monthly data from 1998 through October 2008 for its NEL per customer forecast. FPL's customer forecast relied upon the University of Florida's October 2008 population projections. FPL's economic assumptions used in its NEL model were based upon economic forecasts formulated in the latter half of 2008 from Global Insight, Economy.com and other sources. In light of the current economic conditions, we have concern over the use of historic data to guide us in this current economy and believe adjustments are necessary.

In an attempt to reflect current economic conditions not captured in the historic data, FPL made several adjustments to the output of its NEL per customer econometric model. First, FPL adjusted for the impact of two wholesale contracts. Second, FPL reduced its NEL forecast to capture the influence of changes in the appliance stock and new energy efficiency standards. Third, after adjusting the NEL forecast for these two effects, FPL made a "re-anchoring" adjustment to the output of its NEL model so that the output of the model equaled the latest available actual 2008 level of sales. Fourth, FPL adjusted its NEL per customer forecast to capture the impact of the recent escalation in the number of homes left vacant due to the housing crisis. Many of these vacant homes were still active accounts although they consumed only a small amount of electricity. Because FPL believed that the impact of these vacant homes was not fully reflected in the historical data used to estimate the econometric models, FPL adjusted downwards its NEL per customer forecasts to reflect the presence of these "minimal use customers" during 2009, 2010, and 2011. As a result, FPL projected the number of customers to increase by 0.2 percent in 2009, and increase by 0.6 percent in 2010. FPL projects NEL per customer to decrease by 1.7 percent in 2009, and increase by 0.1 percent in 2010.

We agree with the first two adjustments made by FPL. However, as to the third and fourth adjustments suggested by FPL, we disagree. While FPL's third and fourth suggested adjustments were made to reflect the impact of changing economic times, we believe that OPC witness's Brown's methodology more appropriately incorporates this uncertainty into the load forecast.

With respect to FPL's third suggested adjustment, the "re-anchoring" adjustment, we agree that such an adjustment is appropriate. However, since the increase in the number of "minimal use customers" began prior to 2008, we agree with OPC witness Brown that it is appropriate to apply the "minimal use customer" adjustment to the 2008 output of FPL's NEL model prior to making the "re-anchoring" adjustment.

With respect to FPL's adjustment for "minimal use customers," we find that the measurement of the percentage of customers who normally use a minimal amount of electricity should be based upon data spanning a longer period, such as from September 2002 through December 2007, instead of the shorter time period of August 2003 through December 2004 used by FPL. The use of the longer time period results in increasing the percentage of normally occurring "minimal use customers" from FPL's suggested 7.0 percent to 7.42 percent.

Based on the foregoing, we adopt FPL's load forecast and its first and second adjustments made to account for the impact of two wholesale contracts and to capture the influence of changes in the appliance stock and new energy efficiency standards. We also adjust FPL's load forecast for minimal use customers to reflect a 7.42 percent historical average and find that it is appropriate to perform the "minimal use customer" adjustment to the 2008 output of FPL's NEL model before performing the "re-anchoring" adjustment. As a result of the forecasts and adjustments, in 2010, FPL's revised net energy for load is 111,299,656,865 kWh. This adjustment to FPL's load forecast increases test year revenues by $36,969,000.

<u>2011 PROPOSED SUBSEQUENT YEAR TEST PERIOD</u>

<u>Legal authority to approve base rate increase</u>

FPL petitioned for a $247 million increase in revenue requirements beginning in 2011 in addition to its petitioned for 2010 revenue increase. The 2011 requested increase was based upon a 2011 subsequent test year. As a preliminary matter, the parties asked us to determine whether we have the legal authority to approve a 2011 subsequent year increase such as that asked for by FPL. The parties next asked us to address whether we should, from a policy perspective and from a factual perspective, approve a 2011 subsequent year adjustment.

Our legal ability to use a subsequent year adjustment has previously been confirmed by the Legislature, by the Florida Supreme Court, and by us. In 1983, the Legislature enacted the following amendment to Chapter 366, F.S.:

> The commission may adopt rules for the determination of rates in full revenue requirement proceedings which rules provide for adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods.

Section 366.076(2), F.S. In 1987, we adopted Rule 25-6.0425, F.A.C., allowing us in a full revenue requirements proceeding to approve incremental adjustments for periods subsequent to the initial period in which new rates will be in effect.

The Florida Supreme Court, in the case of Floridians United, held that even without the authority of Section 366.076, F.S., we had the authority to approve subsequent year adjustments. The Floridians United case was an appeal from our prior order granting FPL a 1984 rate increase and a subsequent year adjustment for 1985. While the appellants challenged the constitutionality of the statute (Section 366.076, F.S.) that we relied upon as authority to grant the subsequent year adjustment, the Court never reached that issue. Rather, the Supreme Court agreed that we had authority to grant subsequent year adjustments even prior to the legislative enactment of Section 366.076(2), F.S:

> We agree that PSC's authority to grant subsequent year adjustments predated the enactment of chapter 83-222 and it is therefore unnecessary to address the constitutionality of the chapter. [citations omitted]

Id.

We have used subsequent year adjustments in prior proceedings. In addition to the 1985 subsequent year adjustment for FPL considered in Floridians United, we approved a request by Tampa Electric Company for a projected test year of 1993 and a subsequent test year of 1994. In that docket, we stated that we had authority to do so and that the facts supported our approval of the 1994 subsequent year adjustment for TECO. See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

Based on the foregoing, we determine that we have the legal authority to grant a subsequent year adjustment if the facts warrant such an adjustment. We next address whether FPL has supported its petition for a 2011 subsequent year adjustment.

Policy decision for subsequent year adjustment

OPC asserted that it did not object to the concept of a subsequent test year on legal grounds per se. Rather, OPC disputed the validity of the application of a subsequent test year to this particular docket. Although each of the intervenors objected to our ability to make a subsequent year adjustment, the basis of their objections appeared to be that from a policy and a factual standpoint, FPL did not prove that a 2011 subsequent year adjustment was appropriate. Having acknowledged that we have the legal authority to grant FPL's request for a 2011 subsequent year adjustment, we next examine whether granting FPL's request is appropriate from a policy perspective.

We believe that back-to-back rate increases should be allowed only in extraordinary circumstances. Historically, we have used the test year concept for setting rates. Under this concept, the test year is deemed to be representative of the future, and used to set rates that will allow the utility the opportunity to earn a rate of return within an allowed range. If the test year is truly representative of the future, then the utility should earn a return within the allowed range for at least the first 12 months of new rates.

FPL witness Olivera explained that the Company was requesting a subsequent year increase in base rates effective January 1, 2011, to address the deterioration in earnings that will take place during 2010. According to witness Olivera, the subsequent year adjustment allows us, as well as the Company, and all parties to address in a single proceeding both the 2010 and 2011 needs, avoiding the time and expense of a separate rate proceeding for 2011. FPL witness Barrett testified that:

> Given the significant time and financial resource commitments involved in fully litigated base rate proceedings, the Commission, the Company, and other stakeholders would benefit by minimizing the frequency of these costly proceedings. One mechanism by which the Commission can address this issue is through the use of a Subsequent Year Adjustment for 2011, the year following the Test Year.

According to SFHHA witness Kollen, there is no evidence that there will be actual savings to ratepayers resulting from the avoidance of a separate proceeding sometime in 2010 for rates that will be effective in 2011. If the Company's 2011 test year costs are reduced as the result of the Company's cost cutting efforts compared to its projections for 2011, then the cost of a separate proceeding in 2010 is likely to pale against the effect of such savings in a subsequent proceeding.

We agree with SFHHA that there is no evidence that ratepayers would receive any savings by avoiding a separate rate proceeding sometime in 2010 for rates that would be effective in 2011. FPL witness Barrett admitted that FPL did not perform a cost-benefit analysis to examine whether the costs of a rate case outweighed savings that could result from re-examining changing costs.

The subsequent increase requested in this case is based on a second projected test year of 2011 and is in fact a second full rate case filing. FPL claims that this second case is necessary "to address the deterioration in earnings that will take place during 2010." However, it is important to note here that filing two general rate cases with back-to-back projected test years deprives us and deprives the Company's ratepayers of the benefit of an additional twelve months of actual economic data and operating history of the Company. This additional data could be used to validate whether an additional increase is truly necessary and whether the second test year is really representative of the future.

The Company's ratepayers deserve a full investigation into the cause of FPL's claimed deterioration of its earnings. Two general rate increases that are barely twelve months apart justify the time and expense of a second separate proceeding. Two back-to-back general rate increases are especially of concern when one considers that the need for base rate increases has already been reduced for FPL due to the effect of the cost recovery clauses. Cost recovery clauses provide for approximately 61 percent of FPL's revenue and reduce the risk of under-recovery of a substantial portion of FPL's operating costs. The recovery of costs through the clauses should limit the need and frequency of full rate cases for FPL.

States that make use of a projected test year, like Florida, typically only attempt to look one year into the future. FPL is asking us to look far beyond the horizon, into 2011, and raise consumers' rates not only in 2010 based on a 2010 projected test year, but to raise consumers rates again in 2011 based on speculative and untested projections for a 2011 subsequent projected test year. These test years were developed in 2008. As one reaches farther into the future, predictions and projections of future economic conditions become less certain and more subject to the vagaries of changing variables. This is particularly true given that for 2010, FPL projected results based upon the assumption of a "down economy," and for 2011 projected results based upon a "down economy just beginning to recover."

Because of unpredictable changes in the economy, it is certainly possible that FPL's perceived need for a 2011 base rate increase could be offset by changes in sales growth, billing determinants, additional Stimulus Bill of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill) benefits, and other cost-decreasing measures. At a time when Florida's ratepayers have been hit hard by the downturn in the economy, it makes sense to wait and see if a subsequent rate case is justified. FPL's claim that it will need a rate increase in 2011 simply is too speculative, and is hereby rejected.

<u>Factual support for 2011 subsequent year adjustment</u>

We realize that our decision on the policy of whether a subsequent year adjustment is appropriate incorporates many of the facts from the case. However, we think it important to address in more detail the appropriateness of the 2011 test year and whether the facts in this docket support the use of a 2011 subsequent year adjustment. FPL witness Barrett explained that the Company provided forecasted information for 2009, 2010, and 2011 for use in this proceeding. The Company included 2011 year data in support of its requested Subsequent Year Adjustment. According to witness Barrett, FPL applied the same rigor to its forecast of 2011 as it did for 2009 and 2010, to be confident that the costs proposed were appropriate for setting rates in this proceeding.

FPL witness Barrett stated that final approvals for these forecasts were made in late 2008 and reflected the Company's best assessment of the business environment. Discussing the prevailing business environment at the time the forecasts were being finalized, witness Barrett

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testified that "All of these factors have combined to plunge Florida into an economic deterioration not seen since the early 1970s. [. . .] Every major assumption used in the forecast reflects the severe economic downturn."

We are concerned with the reliability of the forecasted data used to develop the 2011 test year and subsequent rate increase. FPL has stretched its forecasts far into the future during a period when "every major assumption used in the forecast reflects the effects of the most severe economic downturn since the early 1970's." OPC witness Brown testified that "[t]he farther into the future that a utility attempts to project data, there is a greater amount of uncertainty and the data becomes less reliable." Witness Brown further noted that "This is particularly of concern as our country and the customers in FPL's service territory are facing the current economic crisis. Projections of when and how economic recovery will occur are extremely speculative."

The forecasted 2011 test year was prepared in late 2008, when the economic environment was extremely volatile. The last month of the 2011 test year was at least 36 months away from the last actual historical data point when the forecast was prepared. Even in times of economic stability, projections this far in the future strain the reliability and accuracy of data that is needed to set rates.

SFHHA witness Kollen testifed that the record was insufficient for us to determine what the reasonable revenues and costs would be in 2011, given the present economic uncertainty:

> First, the Commission cannot determine at this time what the reasonable revenues and costs will be in 2011 given the present economic uncertainty. It will be difficult enough to determine the reasonable level of revenues and costs for the 2010 test year, which itself is two years removed from actual experience and is based on a budgeting process covering 2009 and 2010, but which began in mid-2008 prior to the meltdown in the financial markets and the recession. Since 2008, the Company has engaged in extensive cost reductions compared to its 2009 budget, thus rendering the 2009 budget unreliable as the basis for the 2010 test year forecast, and even more so for the 2011 subsequent test year forecast.

In the first four months of 2009, the Company experienced a $38 million budget variance in O&M expenses and a $169 million budget variance in capital projects. Both of these variances were favorable and were explained by FPL witness Barrett. However, variances of this magnitude, in the very beginning of a forecast, when projections should be the most accurate, show how unpredicted events and management's reactions to the actual business conditions can make projections inaccurate. The further those projections go into the future, the less predictable the underlying assumptions become.

<u>Forecast of customers</u>

Above, we addressed FPL's overall projections for 2011 and stated our concern for their accuracy. We now address the appropriateness of FPL's 2011 forecast of customers, kWh, and kW which were sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser.

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FPL used the same methodology for its 2011 forecast by revenue and rate classes, as it did for its 2010 forecast. OPC witness Brown testified that, due to the uncertainty associated with the current economic downturn, economic projections of when an economic recovery will occur are extremely speculative. She also noted that if the economic recovery was either faster or greater than expected under FPL's assumptions, there would be a potential for excess earnings at ratepayers' expense. She concluded by saying that although OPC was willing to accept the uncertainty associated with a 2010 test year, the 2011 test year projections incorporate an unacceptable additional level of uncertainty and should be rejected.

We share OPC witness Brown's concern that economic projections formulated in late 2008 and extending through 2011 incorporate an unacceptable level of uncertainty for the purpose of setting rates. Hearing Exhibit 412 is illustrative of our concern. This exhibit showed the Low, Medium, and High Case scenarios for the University of Florida's population forecast used in FPL's customer growth model. As this exhibit showed, as the forecast horizon extended further into the future, the range between the Low and High Case scenarios became wider. We believe that this wider range is indicative of the University of Florida's acknowledgement that its forecast for population growth is subject to more variability as the forecast horizon extends further into the future. Furthermore, as acknowledged by FPL witness Morley under cross examination, the University of Florida revised its population forecast "with some frequency" during 2008. These revisions, which extended into 2009, added an additional degree of variability to the population projections as the forecast bands shifted either upward or downward. Because the population projection from the University of Florida was the primary driver in FPL's customer model, increased variability in the 2011 population projection led to increased variability in the number of customers in 2011. Because of the way FPL's models were structured, an increase in the variability of the number of customers in 2011 flowed through to total NEL, and ultimately to the number of customers and kWh sales by revenue class.

Because there was no empirical data (such as stabilized customer growth rates) in the record to indicate that the uncertainty associated with the current economic downturn was nearing an end, we are concerned that during the twelve months of 2010, additional economic volatility could cause the number of customers and kWh sales in 2011 to deviate significantly from FPL's projections.

In conclusion, while we recognize that we have the legal authority to grant a subsequent year adjustment when the facts so warrant, we decline to do so in the present case. FPL's 2011 subsequent test year and its forecasts of customers, kWh, and kW by revenue and rate classes for the 2011 projected test year are too speculative and are therefore not appropriate for rate setting purposes. The projection period is too far in the future and was developed in times of great economic instability to have confidence in the integrity of the data. Actual events in 2009 have already shown the potential for significant variance from the projections. In denying FPL's petition for a 2011 subsequent year adjustment, we recognize that if the Company is unable to earn within its allowed range of return, it has the option of filing for a base rate increase including a request for interim rate relief. Accordingly, we find that FPL's projected subsequent test year of 2011 is not appropriate and we deny FPL's request for a subsequent increase in January 2011 based on this record.

GENERATION BASE RATE ADJUSTMENT

For the reasons explained in detail below, we do not approve FPL's request for a Generation Base Rate Adjustment (GBRA) mechanism that would authorize FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time they enter commercial service. The existing ratemaking procedure provided by Florida Statutes and our rules provides for a more rigorous and thorough review of the costs and earnings associated with new generating units. Section 366.06(2), F.S., provides that when approved rates charged by a utility do not provide reasonable compensation for electrical service, the utility may request that we hold a public hearing and determine reasonable rates to be charged by the utility. Section 366.071, F.S., provides expedited approval of interim rates until issuance of a final order for a rate change. Rule 25-0243, F.A.C., establishes the minimum filing requirements for utilities in a rate case. These procedures have been sufficient in the past for FPL and other regulated utilities wishing to recover capital expenditures when a new generating facility begins commercial service. We find that the GBRA shall expire as scheduled when new rates are established as delineated in this Order.

GBRA Background

The GBRA was one of several elements of a negotiated settlement agreement between the parties that we approved in FPL's 2005 rate case, Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company (2005 Settlement Order). The GBRA permitted FPL to increase base rates to recover capital costs associated with new generation facilities as they entered commercial service. The stipulation specified the basis for the costs, as well as the return on equity and capital structure to be used in the calculation of the cost factor to be submitted for our approval using the Capacity Clause projection filing for any necessary true-up. Other elements of the settlement agreement prohibited FPL from petitioning for an increase in retail base rates during the term of the agreement, and established a revenue sharing arrangement between FPL's shareholders and customers. The conditions under which we approved the negotiated settlement agreement are far different from the proposal to establish the GBRA in this case.

Differences From the 2005 Stipulation

FPL's current request to permanently establish the GBRA differs markedly from the 2005 negotiated settlement agreement that we approved.[2] Acceptance of the GBRA provision of the settlement agreement was contingent upon several provisions, a result of the "give-and-take" in negotiating the agreement. First, the stipulation specified the term of the agreement as effective for a minimum of four years – January 1, 2006, through December 31, 2009 – and to remain in effect until new base rates and charges become effective by order of the Commission.[3] FPL's current request to continue the GBRA specifies no end date. Second, FPL's base rates could not change during the term of the settlement agreement; FPL's current request to continue the GBRA specifies no restriction on changes to base rates. Third, the negotiated agreement provided a

[2] Id.
[3] Ibid., Attachment A, page 3.

revenue sharing plan between shareholders and customers. FPL's current request to continue the GBRA specifies no such revenue sharing arrangement. To date, FPL has flowed $386,928,000 through the GBRA mechanism for three generating units as a result of the stipulated settlement.[4] If the GBRA is made permanent, the amount that FPL proposes to add to rate base under the GBRA mechanism is $3.2 billion over the next five years.[5]

FPL witness Ousdahl acknowledged that the GBRA is materially different from a rate case, because it is an interim base rate measure. We agree that the GBRA specified in the settlement agreement is an interim measure because it has an ending date, and costs would be rolled into base rates at the next rate case. The GBRA mechanism that FPL has asked us to approve in this docket would have no such limit. It has no ending date, and it is intended to cover the costs of all future power plants that receive need determination approval. As FPL witness Barrett acknowledged, the GBRA mechanism would allow FPL to recover such costs without regard to whether earnings were sufficient to cover the addition of a new plant.

Existing Ratemaking Policy and the Proposed GBRA

Parties are in agreement that rate cases are often costly and administratively burdensome. For example, the expenses associated with FPL's rate case in this docket were estimated at $4 – 5 million during the hearing. Comparatively, the cumulative total rate increase that FPL requested is approximately $1.5 billion. FPL's requested rate increase included new power plants, transmission and distribution projects, administrative costs, operation and maintenance expenses, and other expenses.

The record indicates that FPL built several generating units since 1985 without seeking a rate increase. FPL witness Barrett also acknowledged that if economic conditions or other factors changed, it was possible that FPL's base rates could be sufficient to cover the cost of a new generating unit in whole or in part without the application of a GBRA. Other factors, such as the addition of new customers and increased electricity sales tend to offset the additional costs of new power plants. FPL witness Barrett testified that under certain hypothetical circumstances, with a GBRA mechanism in place, customers' bills could go up as a result of adding new generation, though FPL's earnings would remain unaffected.

According to FPL, we should approve continuation of the GBRA because it is "reasonable, cost-based and sends the appropriate price signals to customers." While the term "cost-based" may accurately describe the GBRA, a rate case proceeding provides more of an opportunity to rigorously review costs and earnings as a whole. Regarding the price signals, we agree that implementation of the GBRA may link reductions in fuel costs to increases in base rates that may occur as a new plant is put in service. However, a traditional base rate proceeding could also be timed (based on the Company's request) to coincide with the in-service date of a new plant, thus achieving the same result. FPL witness Barrett testified that it is possible for the Company to structure the timing of a rate request associated with a new plant so that both the

[4] The jurisdictional revenue requirements $121,310,000 for Turkey Point 5, $138,519,000 for West County 1, and $127,099,000 for West County 2.
[5] Representing costs of FPL's West County Unit 3, Cape Canaveral, and Riviera Beach projects.

plant's costs and its fuel savings benefits are received by the customer at the same time. FPL witness Pimentel stated that "the reason that we're requesting the GBRA, first and foremost, is as we build generation that's been approved by this Commission in need determinations, we're trying to match the customer savings and fuel efficiency with the actual capital that we are putting into the business." This goal could be achieved within the process of a traditional rate case.

Another of FPL's arguments for the GBRA mechanism was that it has the potential to avoid the need for a rate case. It is not possible for us or interested parties to examine projected costs at the same level of detail during a need determination proceeding as we would be able to do in a traditional rate case proceeding. A need determination examines costs only in comparison to alternative sources of generation. It does not allow for a review of the full scope of costs and earnings, as a rate case does. FPL witness Barrett acknowledged that the GBRA mechanism would be a limited-scope proceeding focused only on the GBRA, and intervenors would not be able to raise other cost issues in such a proceeding. SFHHA witness Kollen also argued against the GBRA because FPL would have the ability to impose a base rate increase for new generation and transmission projects without consideration of other revenues and costs. OPC witness Brown explained that if the GBRA is approved and the economy subsequently recovers, FPL's shareholders may earn greater returns that could be sufficient to cover the cost of new generating units without increasing base rates. According to OPC, having a GBRA mechanism in place would mean FPL would have less incentive to control overall costs. Witness Brown also pointed out that under the GBRA, FPL would essentially be "imposing a surcharge on customers' bills to cover the costs associated with a single component of its overall costs of providing service," and we would not have the ability to evaluate whether FPL's existing base rates were sufficient to cover some or all of the costs.

The time period required for a traditional rate case proceeding differs from that required for need determination proceedings that the GBRA mechanism would utilize. Rate cases generally take at least eight months to complete and include five months devoted to discovery prior to hearing, in accordance with Section 366.06, F.S. Need determination proceedings are required to be completed within 135 days from the date a petition is filed per Section 403.519 (4), F.S. Witness Barrett stated that the GBRA mechanism protects customers "in the event that we're able to bring in a unit less than the costs that were estimated for that unit and approved through the need process, so there would be an automatic true-up for customers." Witness Barrett also acknowledged, however, that a rate case serves as the ultimate true-up, and a rate case is generally beneficial for regulators and customers.

Witness Ousdahl agreed with the statement that "One of the benefits of a base rate proceeding from a consumer's perspective is that a base rate proceeding would examine a utility's entire cost of service to determine whether reductions in rate base may offset capital additions." Witness Ousdahl also agreed that as part of a base rate proceeding we have the opportunity to examine whether a utility's accumulated depreciation or increases in a utility's billing determinants would result in a decrease in its rate base. One criticism that SFHHA witness Kollen had of the GBRA mechanism is that "it provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reductions in all other costs."

Witness Kollen was also concerned that the GBRA mechanism that FPL asked us to approve was not clearly defined. Witness Kollen pointed out that "the GBRA mechanism is not even a proposed tariff even though it is self-implementing. There is no proposed tariff to review. There is not even a detailed description of the mechanism and the revenue requirement computations in the testimony of any FPL witness." FPL is currently building several new power plants, West County 3, Riviera Beach, and Cape Canaveral. Witness Deaton acknowledged that between 2010 and 2015, FPL will be adding $3.255 billion in capital costs to rate base for these power plants if we approve the GBRA. This suggests that in the absence of the GBRA, FPL may file a rate case in 2013 for the next new plant.

The record shows that FPL already collects about 61 percent of its total revenues through various "pass-through" mechanisms and cost recovery clauses. We are not convinced that adding another such mechanism, by permanently implementing a GBRA for FPL, would provide advantages over traditional rate case procedures found in Section 366.06, F.S. We find no justification in the record for approving a cost-recovery mechanism for FPL's new generation that is different from what applies to all other investor-owned electric utilities. Approving a GBRA for FPL on a permanent basis would constitute a significant change in our general ratemaking policies. As we said in Order No. PSC-09-0283-FOF-EI: "[a]cceptance of a settlement among parties is not the same as establishing a generic policy." [6] FPL witness Ousdahl stated: "We are asking the Commission to formalize its policy with regard to GBRA." We are not inclined to formalize our policy with regard to GBRA in the manner FPL requested. There is no record evidence, beyond FPL's suggestion, supporting adoption of a GBRA-like procedure for other utilities. We do not want to set such a precedent here.

We deny FPL's request to continue the GBRA mechanism. It is not possible for us to exercise as adequate a level of economic oversight within the context of a GBRA mechanism as we can exercise within the context of a traditional rate case proceeding. Furthermore, a policy change of this magnitude, which would ultimately affect other utilities, deserves a more thorough review through a separate generic proceeding.

JURISDICTIONAL SEPARATION

FPL's witness Ender testified that the Company's 2010 transmission service revenues were allocated as credits to offset retail jurisdictional revenues consistent with our order in FPL's last fully litigated rate case, but witness Ender did note that, historically, we have required utilities to separate, not credit back, any costs and revenues associated with firm wholesale transmission sales that last over one year in duration.

According to OPC's witness Brown, FPL created a revenue credit methodology that charged the retail jurisdiction with all costs of transmission, and provided an offsetting revenue

[6] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 126.

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credit for transmission revenues received from non-retail jurisdictional customers. Witness Brown contended that while FPL's approach might be appropriate for non-firm or short-term transmission services, revenue crediting for long term contracts could create a subsidy for long-term firm transmission service customers. To remove the effect of this revenue credit method, witness Brown stated that FPL would need to reduce its requested jurisdictional revenue requirements by $18.5 million in 2010.

In his rebuttal testimony, witness Ender indicated that FPL did not oppose OPC's method of addressing transmission related costs and revenues for long-term firm non-jurisdictional transmission service contracts, but the actual revenue amount that should be separated was approximately $23.0 million. OPC agreed with the adjusted amount.

We agree with OPC's position on this matter. Separating all revenues and costs associated with forecasted long-term firm non-jurisdictional transmission service contracts ensures that jurisdictional customers will not subsidize non-jurisdictional transactions. We also agree that the information concerning the costs and revenues associated with these sales is more accurately presented, based on forecasted transactions for 2010, by FPL.

Based on the above, we find that all costs and revenues associated with long-term firm non-jurisdictional transmission service contracts shall be separated. We make the following jurisdictional adjustments to remove the effects of the revenue crediting method employed by FPL: reduce plant in service by $386,896,000; reduce accumulated depreciation by $144,299,000; reduce plant held for future use by $4,200,000; reduce construction work in progress by $18,623,000; increase working capital by $3,700,000; decrease operating revenues by $33,639,000; decrease O&M expenses by $10,462,000; decrease depreciation and amortization by $10,352,000; decrease taxes other than income by $4,918,000 and increase amortization of regulatory asset by $17,000. We also find that FPL appropriately separated all other costs and revenues between the wholesale and retail jurisdictions.

QUALITY OF SERVICE

FPL provides electric service to about 4.4 million customers. FPL's service territory covers 28,000 square miles, uses 67,000 miles of electrical conductor consisting of 42,000 miles of overhead wires and about 25,000 miles of underground cable, 1.1 million poles, and approximately 800,000 transformers. The distribution business unit is divided into five regions (North, East, West, Broward, and Miami-Dade), which are further divided into seventeen management areas with 35 service centers.

The quality and reliability of the electric service provided by a utility is objectively measured through the use of electric industry reliability indices and the number and types of customer complaints. We have established specific reporting requirements and reliability indices in Rule 25-6.0455, F.A.C., which are used to analyze the quality and reliability of an electric utility's distribution system. The reliability indices track the duration and frequency of power interruptions and are typically examined at a system level. The System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and the Customer Average Interruption Duration Index (CAIDI) are the most common indices. In effect, they are measures of unreliability. As the indices increase, reliability becomes worse. All of the indices provide information about average system performance over a specific time period. Accordingly, it is best to examine the current results of a single utility and make a determination as to whether the trend of the current and past results are improving or worsening. However, using averages as the sole basis for decision making can mask the interruption for a specific customer. Therefore, it is important to recognize that an individual customer's outage experience will be averaged within the system indices and that customer complaints relating to the utility's service quality must also be analyzed.

Service Hearings and Complaints

The Commission conducted nine service hearings in FPL's service territory that began on June 19, 2009, and concluded on June 26, 2009. The service hearings took place in Sarasota, Fort Myers, Daytona Beach, Melbourne, West Palm Beach, Fort Lauderdale, Miami, Miami Gardens, and Plantation. A total of 418 customers testified at the service hearings, covering topics that ranged from billing issues, deposit requirements, support of FPL, lack of support for the rate base adjustment, and service quality issues. Service quality issues were reported by 55 customers or approximately 13 percent of the customers at the service hearings.

At the technical hearing, during cross examination on FPL's Service Hearing Report, FPL witness Santos explained that the complaints concerning outages and service reliability are handled by the distribution business unit and that the service reliability issues were addressed by that unit. Our review of the Service Hearing Report concerning service reliability indicates that the momentary power interruptions (MPIs) experienced by many of FPL's customers involved vegetation or lightning strikes. In order to resolve the MPIs that did not involve lightning strikes, FPL reported that the Vegetation Management Department was either scheduled to perform trimming or was in the process of correcting problems that were identified following vegetation surveys concerning the customer complaints. FPL witness Spoor testified that the outages caused by vegetation appeared to be trending upward for the years 2006 through 2008 and that the years 2004 and 2005 experienced natural pruning caused by the hurricanes. As the AG pointed out in its brief, MPIs and outages related to vegetation do appear to be increasing.

Regarding customer complaints, staff witness Hicks testified that 14,700 complaints were logged against FPL for a two year period between July 1, 2007, and June 30, 2009. Of the logged complaints, 12,236 were directly transferred to FPL through our Transfer-Connect program. The most common FPL complaints were billing issues, which accounted for 71 percent of the complaints during the two year period while 29 percent involved quality of service issues. In her rebuttal testimony, FPL witness Santos responded that the data shows on an annual basis only 0.16 percent of FPL customers contacted us with service complaints. According to witness Santos, that demonstrates that FPL has a very low rate of complaints, and compares favorably to the other Florida IOUs.

With respect to the J.D. Power 2009 residential customer satisfaction study for the South Region Large Segment, FPL witness Olivera agreed that the study shows FPL slightly below average. In explaining, witness Olivera stated that the J.D. Power study examines a ". . . whole bunch of dimensions," not just reliability. Witness Olivera also stated the average for the East Region Large Segment is 593, whereas FPL is 632, which is above the Southeast Region Large Segment. We agree with FPL, in principle, that an analysis of adequate electric reliability should not be based on a single dimension. In this case, however, the service reliability complaints plotted in the Review of Florida's Investor Owned Utilities' Service Reliability in 2007 indicated in Figure 4.9 that the reliability related complaints reported to us for FPL have been trending slightly upward since 1999. Service reliability complaints included service interruptions, quality of service, repair, safety, and trees. The observation that customer service reliability complaints reported to us are trending upward lends support to the AG's argument that the service hearings held within the FPL service territory indicated that FPL's service varies in different locations. Therefore, we can not agree that FPL is ". . . operating well beyond the level required to provide reliable electrical service." In our view, the electrical service reliability of FPL's system is more appropriately characterized as adequate.

Reliability Indices

FPL witness Sonnelitter testified that FPL's transmission reliability was in the top 10 percent of the utilities surveyed in a recent bench marking study. FPL's transmission SAIDI indicted that when an outage occurred on the transmission system it lasted for less than one minute or 0.5 minutes, whereas for the Southeast Region of the US, transmission SAIDI lasted for 5.8 minutes.

As mentioned above, Rule 25-6.0455, F.A.C., requires each electric investor owned utility to file an Annual Distribution Reliability Report with us. The report contains a number of mathematical calculations relating to the duration and frequency of outages that occur on a utility's distribution system on an actual and adjusted basis. FPL witnesses Spoor and Reed testified that FPL's three indices (SAIDI, SAIFI, and CAIDI) indicated that FPL was providing better than average numbers for the distribution system.

FPL's distribution system SAIDI is graphically represented in Figure 1 below and shows that for the years 2004 and 2005 an average interruption lasted for 70 minutes and in 2006 an interruption lasted an average of 74 minutes. SAIDI declined in 2007 and sharply declined in 2008 to 67 minutes.

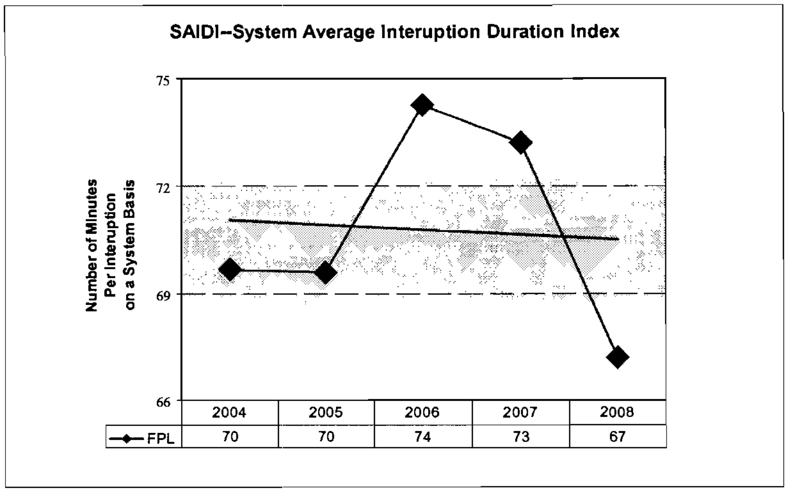

Figure 1. SAIDI

FPL's distribution system analysis also includes the frequency or number of times an interruption occurred on the distribution system. Figure 2 indicates that FPL customers experienced 1.2 outages in 2004, and in 2008 the number of outages declined to 1.07 outages. This metric is used in conjunction with SAIDI.

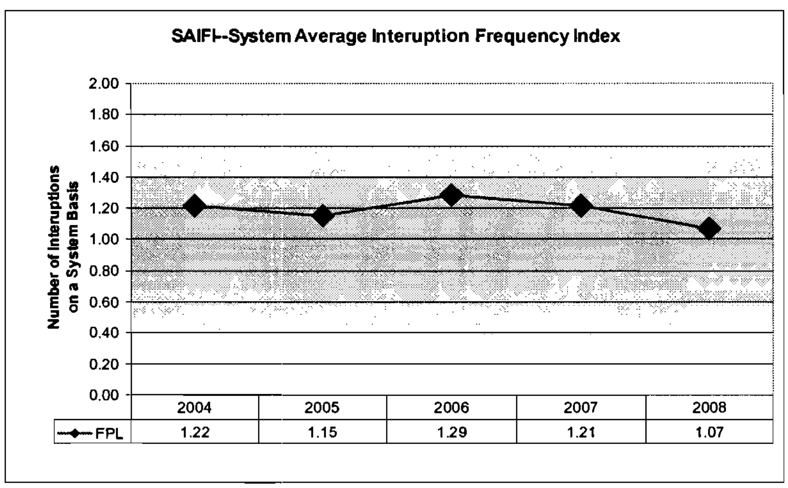

Figure 2. SAIFI

The remaining metric or index is CAIDI, and it represents the length of time, in minutes, that an FPL customer can expect a distribution system outage or interruption to last. Figure 3 indicates that CAIDI had a low of 57 minutes in 2004 and increased to 63 minutes in 2008.

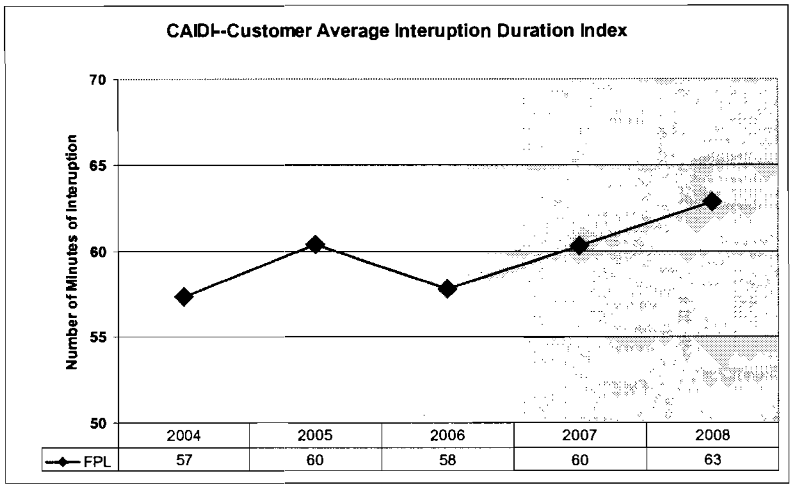

Figure 3. CAIDI

The SAIDI index includes the other indices of SAIFI and CAIDI. SAIDI for FPL's entire distribution system is trending downward. This is a good indication that the length of time a customer experiences an outage is decreasing and in 2008 SAIDI had decreased to 67 minutes.

Based on the above, we find that the quality and reliability of the electric service provided by FPL is adequate. We make this determination based on an analysis of customer complaints, an analysis of the distribution system metrics that include SAIDI, SAIFI, CAIDI, and the analysis of the metrics for the transmission system – System Average Restoration Index (SARI) and SAIDI. We note, however, that outages and momentary power interruptions caused by vegetation do appear to be increasing, and we expect our staff to continue to monitor that trend.

DEPRECIATION STUDY

Capital recovery schedules

Under the capital recovery schedule mechanism, the investment and associated reserve of installations facing near-term retirement are separated out as sub-accounts, and the unrecovered net amounts are amortized over the period of their remaining service to the public. The mechanism is in our depreciation rule, and is the standard practice of this Commission.[7]

FPL's proposed capital recovery schedules address the unrecovered costs associated with the near-term (2010-2013) retirement of the Cape Canaveral and Riviera steam plants, the St. Lucie and Turkey Point nuclear uprate projects, and the meters made obsolete by the new AMI

[7] 2005 Settlement Order; Order No. PSC-99-0073-FOF-EI, issued January 8, 2009, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company; and Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, in Docket No. 931231-EI, In re: Request for change in Depreciation Rates by Florida Power and Light Company.

technology. FPL asserted that the use of capital recovery schedules ensures that recovery of retired equipment occurs close to, or before, their retirement. The proposed recovery period of four years coincides with the period between depreciation studies, and closely matches the remaining period the associated assets will be providing service.

OPC did not dispute the need for capital recovery schedules, but did dispute how the costs should be recovered. OPC witness Pous proposed that: (1) the unrecovered costs associated with the retirement of the Cape Canaveral and the Riviera power plants be offset by a portion of FPL's identified reserve surplus for the steam production investment; (2) the unrecovered costs associated with the nuclear uprates be offset by a portion of FPL's identified reserve surplus for the nuclear production investment; and (3) the unrecovered costs associated with obsolete meters retiring due to AMI technology be offset by a portion of FPL's identified reserve surplus existing in the distribution function. This would eliminate the capital recovery schedule expense and reduce the reserve surplus.

If recovery is not afforded for these identified net unrecovered near-term retirements during their remaining period of service, a negative reserve component will result relating to plant no longer providing service. We agree with OPC that a portion of the reserve surplus can and should be used for the immediate recovery of these costs. This action will reduce the test year depreciation expense as well as the reserve surplus.

SFHHA proposed that: (1) FPL's identified unrecovered costs associated with the near-term planned retiring Cape Canaveral and Riviera facilities should be added to the capital costs of the new repowered generating units; (2) the remaining net book value of the retired nuclear assets should be added to the uprated units for continued depreciation over the lives of those units; and (3) the remaining net book value, including removal costs of the retired meter investment, should be depreciated at the same rate as approved for the meter investment. SFHHA witness Kollen contended that:

- FPL's revenue requirement already includes the cost of advanced meters, so there is no need to accelerate the depreciation of old non-AMI investment;
- FPL's AMI deployment is the cause for the retirements of the existing non-AMI meters; therefore, it is reasonable to reclassify the existing non-AMI meters as a regulatory asset;
- FPL's proposal would require ratepayers to pay for existing non-AMI meter investment and the new AMI meter investment at the same time; and
- Since the existing non-AMI meters will be replaced at one time over a four-year period, FPL's four-year amortization proposal would "double-up" recovery for meters during that period.

FPL witness Davis asserted that he agreed that nuclear uprate costs relating to plant additions should increase the plant investment and be depreciated over the life of the related group of assets. However, witness Davis disagreed that the net book value of the identified nuclear uprate retirements and associated removal costs should be deferred and recovered over

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the remaining licensed life of each nuclear unit. Regarding the replacement of obsolete meters with new AMI meters, witness Davis disagreed that FPL is "doubling up," as SFHAA suggested.

The purpose of depreciation is to match expenses to the period the assets associated with those expenses are providing service to the public. Under group depreciation, it is recognized that some assets within the group will experience a life shorter than the average, while others will experience a life longer than the average. However, if there is a group of assets planned for near-term retirement that now have a significantly shorter life than the overall group life, the associated investments should be withdrawn from the group and recovered over their expected life as provided by our rules. This is the principle of matching expenses to consumption.

If assets retire earlier than the average life of the group without recovery being afforded, a negative reserve component is created. The negative reserve component translates into a positive rate base element. From the Company's standpoint, it will continue to earn a return on this non-existent plant over the life of the group. From the ratepayers' standpoint, they will continue paying for plant no longer providing service until the situation is corrected. Negative reserve amounts are non-life related net investments[8] that we have historically corrected as fast as practicable to remedy the existing intergenerational inequity.[9]

SFHHA's proposal would create a negative reserve component, the exact situation the capital recovery schedule mechanism avoids. Moreover, deferring recovery is simply mortgaging the future. Ratepayers should pay their fair share of costs associated with plant from which they are receiving service. Unrecovered amounts associated with non-existent plant do not benefit ratepayers. Contrary to SFHHA's assertions, recovery of the identified unrecovered costs associated with planned near-term retirements over a period that matches the remaining period the related assets will provide service ensures intergenerational equity. We disagree that such recovery is "accelerated" as FPL, FIPUG, and SFHHA contended. Recovery that matches the service life is not accelerated; it reflects the matching principle. Finally, offsetting FPL's identified unrecovered costs provides immediate recovery and reduces test year depreciation expense, thus alleviating SFHHA's concerns.

Based on the foregoing, we hereby approve the capital recovery schedules contained in Table 1, on the following page. A portion of FPL's existing reserve surplus shall be used to offset the recovery schedule expenses, as discussed in further detail below.

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[8] Non-life related net investments refer to unrecovered costs associated with plant that is no longer providing service to the public. Because the related plant has retired, there is no life over which to recover the costs. Thus, they are non-life related costs.

[9] Order No. PSC-09-0229-PAA-GU, issued April 13, 2009, in Docket No. 080548-GU, In Re: 2008 depreciation study by Florida Public Utilities Company, p. 3; Order No. PSC-03-0260-PAA-GU, issued February 24, 2003, in Docket No. 010906-GU, In re: Request for approval of depreciation study for five-year period 1996 through 2000 by Sebring Gas System, Inc., p. 3; Order No. PSC-02-1492-PAA-GU, issued October 31, 2002, in Docket No. 010383-GU, In re: Application for approval of new depreciation rates by Tampa Electric Company d/b/a Peoples Gas System, p. 3; Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 010669-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities Company, p. 2.

Table 1

Steam Plant Retirements	Estimated Investment 12/31/2009	Estimated Reserve 12/31/2009	Estimated Cost of Removal	Total Unrecovered costs
Cape Canaveral Common				
311 Structures & Improvements	14,150,126	12,611,980		1,538,146
312 Boiler Plant Equipment	1,849,558	674,585		1,174,973
314 Turbogenerator Units	1,022,283	537,299		484,984
315 Accessory Euqipment	727,205	400,288		326,917
316 Misc. Equipment	649,164	635,515		13,649
Total Cape Canaveral Common	18,398,336	14,859,667		3,538,669
Cape Canaveral Unit 1				
311 Structures & Improvements	1,699,261	1,185,805		513,456
312 Boiler Plant Equipment	58,317,673	49,045,408		9,272,265
314 Turbogenerator Units	29,691,699	17,501,297		12,190,402
315 Accessory Euqipment	4,575,178	3,411,278		1,163,900
316 Misc. Equipment	454,247	446,053		8,194
Total Cape Canaveral Unit 1	94,738,058	71,589,841		23,148,217
Cape Canaveral Unit 2				
311 Structures & Improvements	1,460,458	1,476,474		(16,016)
312 Boiler Plant Equipment	49,029,068	45,864,642		3,164,426
314 Turbogenerator Units	18,405,448	12,974,004		5,431,444
315 Accessory Euqipment	4,980,181	4,984,124		(3,943)
316 Misc. Equipment	516,363	476,595		39,768
Total Cape Canaveral Unit 2	74,391,518	65,775,839		8,615,679
Riviera Common				
311 Structures & Improvements	9,194,438	93,788,335		(84,593,897)
312 Boiler Plant Equipment	651,151	580,853		70,298
314 Turbogenerator Units	1,221,674	1,115,841		105,833
315 Accessory Euqipment	2,048,442	2,056,365		(7,923)
316 Misc. Equipment	838,293	765,531		72,762
Total Riviera Common	13,953,998	13,897,425		56,573
Riviera Common Unit 3				
311 Structures & Improvements	323,577	169,948		153,629
312 Boiler Plant Equipment	26,644,720	24,867,091		1,777,629
314 Turbogenerator Units	20,348,570	16,753,158		3,595,412
315 Accessory Euqipment	2,480,171	2,404,136		76,035
316 Misc. Equipment	117,897	57,070		60,827
Total Riviera Common Unit 3	49,914,935	44,251,403		5,663,532
Riviera Common Unit 4				
311 Structures & Improvements	107,740	105,392		2,348
312 Boiler Plant Equipment	20,735,379	18,833,063		1,902,316
314 Turbogenerator Units	15,546,279	14,814,063		732,216
315 Accessory Euqipment	3,401,126	2,156,145		1,244,981
316 Misc. Equipment	47,438	45,433		2,005
Total Riviera Common Unit 4	39,837,962	35,954,479		3,883,483
Total Steam Plant Retirements	291,234,807	246,328,654		44,906,153

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Table 1

	Estimated Investment 12/31/2009	Estimated Reserrve 12/31/2009	Estimated Cost of Removal	Total Unrecovered costs
Nuclear Uprates				
St. Lucie Unit 1				
322 Reactor Plant Equipment	3,089,857	1,285,383	2,171,874	3,976,348
323 Turbogenerator Units	46,415,739	23,026,980	11,780,444	35,169,203
324 Accessory Euqipment	108,098	107,964	1,675,065	1,675,199
Total St. Lucie Unit 1	49,613,694	24,420,327	15,627,383	40,820,750
St. Lucie Unit 2				
322 Reactor Plant Equipment	8,170,947	5,445,563	788,236	3,513,620
323 Turbogenerator Units	68,116,907	47,503,584	12,173,427	32,786,750
324 Accessory Euqipment	444,059	280,915	984,302	1,147,446
Total St. Lucie Unit 2	76,731,913	53,230,062	13,945,965	37,447,816
Turkey Point Common				
322 Reactor Plant Equipment	254,355	26,072		228,283
323 Turbogenerator Units	2,065,043	144,410		1,920,633
Total Turkey Point Common	2,319,398	170,482		2,148,916
Turkey Point Unit 3				
321 Structures & Improvements	541,965	440,388	289,308	390,885
322 Reactor Plant Equipment	13,326,530	12,658,412	15,309,927	15,978,045
323 Turbogenerator Units	37,480,833	22,160,888	12,054,706	27,374,651
324 Accessory Euqipment	371,220	366,648	183,116	187,688
Total Turkey Point Unit 3	51,720,548	35,626,336	27,837,057	43,931,269
Turkey Point Unit 4				
321 Structures & Improvements	192,250	192,250	290,492	290,492
322 Reactor Plant Equipment	13,393,985	13,120,597	15,326,786	15,600,174
323 Turbogenerator Units	40,012,223	24,247,736	12,047,391	27,811,878
324 Accessory Euqipment	314,044	314,044	183,694	183,694
Total Turkey Point Unit 4	53,912,502	37,874,627	27,848,363	43,886,238
Total Nuclear Uprates	234,298,055	151,321,834	85,258,768	168,234,989
Meters				
370 Obsolete by AMI	249,077,327	171,613,059	23,617,590	101,081,858
Total Capital Recovery Schedules	774,610,189	569,263,547	108,876,358	314,223,000

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Remaining life calculation

For the reasons explained below, we are of the opinion that FPL's calculation of remaining life[10] leads to questionable results. Accordingly, we approve a remaining life calculation based on using the average age of the given account with the selected survivor curve.[11] The remaining lives we approve below are based on this calculation.

OPC disputed FPL's use of a truncated Iowa curve[12] in its life analysis for the production plant accounts. This argument relates to the way in which FPL accounted for interim retirements in its life determinations. Since this is more an issue with an input to the development of remaining life, rather than a calculation issue, we address OPC's arguments in the following section.

As part of its remaining life calculation, FPL allocated the actual book reserve for a given account to the individual surviving balances based on the theoretical or calculated reserve. OPC witness Pous took issue with two aspects of this allocation process. First, the process limited the allocated book reserve to the surviving balance of an individual vintage so that the reserve for the vintage did not exceed the total vintage original cost less net salvage.[13] Second, the impact of net salvage parameters was recognized in the remaining life calculation rather than after the calculation. Witness Pous used an industry standard remaining life calculation, which is the same one that Progress Energy Florida, Inc. (PEF) used in Docket No. 090079-EI.

Regarding his criticisms, witness Pous demonstrated that FPL's remaining life calculation ignored the fact that vintages to which no reserve was allocated were still in service and still accruing depreciation. Moreover, witness Pous explained that in group depreciation,[14] some items of plant are assumed to retire before the average service life while others will retire after the average service life. On average, however, depreciation expenses over the life of the group will equal the total investment adjusted for net salvage. Witness Pous demonstrated that if the book reserve is allocated to all vintages as it should be, different vintage remaining lives result.

FPL explained that it determined the remaining life annual depreciation expense for each vintage by dividing the future book expenses (original cost less book reserve) by the average remaining life of the vintage. The average remaining life for each vintage was a directly

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[10] The remaining life is the period of years remaining, on average, that the group of assets being studied is expected to provide service to the public.
[11] A survivor curve is a graphical picture of the amount of property (in dollars), that exists at each age (in years), throughout the life of a property group.
[12] Iowa curves, published by Iowa State College in 1935, were developed by analyzing the ages at which industrial property had retired. An Iowa curve, when used in conjunction with other inputs, provides the remaining life. A truncated Iowa curve means that no vintage will survive past the estimated date of final retirement.
[13] Net salvage is gross salvage less cost of removal. Gross salvage is the amount received from trade-in or sale of the asset. Cost of removal relates to the costs incurred for the removal and disposal of the retired asset. Net salvage can be either positive where gross salvage exceeds cost of removal, or negative in cases where cost of removal is greater than gross salvage.
[14] Group depreciation assumes that some items of plant will retire before the average service life while others will retire after the average service life.

weighted average derived from the estimated future survivor curve. FPL witness Clarke testified that the remaining life calculated for each vintage took into account that a portion of each vintage will retire before the average service life and a portion will retire after the average service life, consistent with group depreciation concepts. Moreover, by limiting depreciation expenses only to vintages that are not fully accrued, expenses were calculated only for those vintages that had future costs remaining to recover. Witness Clarke contended that this resulted in a composite annual depreciation rate that is appropriate for the plant balances going forward and resulted in the appropriate amount of needed depreciation expenses.

We do not agree with FPL that its remaining life calculation is consistent with FPL's actual practice. FPL does not maintain its plant account reserves by vintage; they are maintained on a total account basis. Also, depreciation rates are not applied to individual vintages; the rates are applied to the total account balance. Allocating the book reserve to individual vintages based on a theoretical reserve calculation is not necessarily a concern. However, in its allocation, FPL determined that the reserve for any given vintage could not exceed the survivors for that vintage less net salvage. For example, in reviewing the calculation presented for Account 396.1, Power Operated Equipment, no reserve was allocated to the 1986-2000 vintages because the allocation of the reserve indicated that these vintages were fully accrued. That is because the most allocated to any given vintage was the surviving investment for that vintage less net salvage. These vintages represent more than 36 percent of the plant account investment. We believe this is a significant amount of investment that has no remaining life. Looking at Account 396.8, Other Power Operated Equipment, FPL uses an L0.5 Iowa curve and 9-year life combination. The average age of the account is 7.5 years. Using the method endorsed by OPC, the remaining life of the account is 5.2 years, compared to the Company's calculation of zero. While this account has an existing reserve surplus, that should not deter from the fact that it does indeed have a remaining life using FPL's proposed curve and life combination.

FPL did not dispute that net salvage impacts its calculation of remaining life. Net salvage impacts the remaining life depreciation rate, not the average remaining life itself.[15] Unfortunately, because FPL's calculation assumes that no vintage can have more reserve allocated than the surviving investment less net salvage, as net salvage varies, so does the remaining life. For all the foregoing reasons, FPL's remaining life calculation leads to questionable results. Accordingly, the remaining lives we address below are calculated by applying the average age of the account to the selected survivor curve. This is similar to OPC's calculation of remaining life and PEF's calculation in its depreciation study in Docket No. 090079-EI. The remaining lives we approve below use this calculation.

Depreciation parameters for production plant

FPL proposed depreciation rates for its plant investment through December 31, 2009. In addition, FPL proposed depreciation rates for production plants projected to become operational after the test year. The depreciation rates for "Future Units" will be implemented at the time of commercial operation.

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[15] Remaining Life Rate = (100-Net Salvage-Reserve)/Average Remaining Life. Rule 25-6.0436 (1)(e), F.A.C.

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The remaining life rate is designed to recover the remaining unrecovered balance (investment less net salvage less reserve) over the remaining life of the associated investment. The formula for the remaining life rate is the plant investment (represented as 100 percent) minus net salvage percent minus reserve percent divided by the average remaining life in years. The reserve represents the portion of the investment accumulated through depreciation expense to date unless restated to another level. Rule 25-6.0436, F.A.C.

FPL used the life span technique in studying its production plants. This technique requires that a date of final retirement be estimated for each production unit. The technique also requires estimation of the level of interim retirements that will occur before the final retirement of the generating unit.[16] The Company used an interim retirement survivor curve[17] to account for expected interim retirements. The curve was developed by performing a statistical analysis that analyzed historical retirements and incorporated judgment and industry information. The economic retirement date of a facility affected each year of installation for the facility by truncating the interim survivor curve for each installation year at the year of expected retirement. The life span[18] for each account was based on the make-up of the property within the given account, experience in the industry, current forecasted life spans, the Company's resource plan, and information from Company personnel. FPL noted that the estimated retirement dates were established for depreciation purposes and did not commit FPL to actually retiring any production units on those dates.

The parties disagreed with the life spans FPL assumed in the depreciation study. The intervenors asserted that FPL's proposed life spans were too short. OPC also disagreed with FPL's level of interim retirements and interim net salvage.

Net salvage is the amount received from gross salvage less cost of removal. Gross salvage is the amount received from sale, reuse, or sometimes the reimbursement from retired property. Cost of removal relates to costs incurred in the removal and disposing of retired plant. Net salvage is positive when gross salvage exceeds cost of removal and negative when cost of removal is greater than gross salvage. Net salvage associated with production plant is associated with the interim retirements expected to retire prior to the retirement date of the generating facility.

1. Life Spans

FPL proposed a 40-year life span for its Scherer and SJRPP coal-fired plants. For the remainder of FPL's steam-fired facilities, FPL proposed a retirement date of mid-2020, resulting in the two newer stations, Martin and Manatee, having life spans ranging from 39 to 44 years, and low 50-year to mid 60-year life spans for the remaining stations. For its combined cycle units, FPL proposed a life span of 25 years.

[16] As an example, interim retirements for a building would consist of assets such as plumbing, heating, doors, windows, and roofs.
[17] A survivor curve graphically depicts the amount of property (in dollars) existing at each age (in years) throughout the life of a group of property.
[18] A life span is the time period when a unit goes into commercial operation and the estimated date of retirement.

OPC witness Pous proposed a 60-year life span for FPL's Scherer and SJRPP coal-fired generating stations. For FPL's Manatee and Martin plants, OPC witness Pous proposed a 50-year life span. The witness did not propose an adjustment to FPL's assumed 25-year life span for combined cycle units even though he asserted that 25 years was artificially short. The witness proposed that FPL be directed to perform a detailed analysis demonstrating why its combined cycle facilities cannot be expected to operate for 35 years or longer, and present the study in its next depreciation study filing. However, the witness suggested that a life span of 30 or 35 years would represent an initial step in bringing FPL's life spans more in line with reasonable expectations.

FIPUG witness Pollock proposed a life span of 55 years for FPL's coal units. For combined cycle units, FIPUG witness Pollock proposed a life span of at least 35 years. FIPUG based its proposed life spans on life spans determined in other regulatory proceedings throughout the country, life spans used by other utilities, and the actual life spans of some of FPL's units.

SFHHA witness Kollen did not address the life span of FPL's coal units, but proposed a life span of 40 years for FPL's combined cycle plants. SFHHA reasoned that if the Putnam combined cycle plant could experience a life span of 42 to 43 years, there was no reason to assume a shorter 25-year life span for other combined cycle units. As additional support for its proposal, SFHHA referred to the experience of other utilities that use a 40-year life span for combined cycle units. Finally, SFHHA asserted that FPL had not demonstrated that it would conclusively operate these units for only 25 years.

In support of its position, OPC asserted that FPL had demonstrated through actual operation that its oil- and gas-fired generating facilities can operate for more than 60 years. OPC witness Pous and FIPUG witness Pollock noted that other utilities and regulatory commissions have recognized 50 to 60 year or longer life spans for steam generating facilities. Moreover, OPC witness Pous referenced the Energy Information Administration of the Department of Energy's database that contains data on generating units demonstrating longer life spans than FPL proposed. Finally, the witness stated that FPL had not provided any economic analysis that demonstrated that its facilities could not operate for longer periods than it had proposed.

FPL contended that the intervenors' reliance on industry statistics from other electric utilities in making their proposals did not consider any of the unique circumstances related to the operations, design life, cycling, or maintenance practices of its production plants. While this may be true, we believe that FPL's actual operations are compelling.

For FPL's coal plants, Scherer and SJRPP, we believe a 50-year life span is appropriate to use in this proceeding. This life span reflects a compromise position between the life spans proposed by FPL and the longer life spans proposed by OPC and FIPUG, and recognizes uncertainties regarding environmental and climate change legislation. For the Manatee and Martin steam plants, we believe that OPC's proposed 50-year life span is reasonable. For the Port Everglades plant, we believe a 60-year life span is appropriate. We also believe that FPL's life span of 59 years for the Sanford plant, 66 years for the Cutler plant, and 53 years for the Turkey Point plant are reasonable.

When combined cycle plants are operating for more than 25 years, this indicates that a 25-year life span is no longer appropriate for depreciation purposes. While FIPUG and SFHHA recommend life spans of 35 or 40 years for combined cycle plants, OPC suggested that 30 to 35 years would be a step in the right direction. Accordingly, we will use a minimum 30-year life span at this time. For those units where FPL has assumed life spans longer than 30 years, no party disagreed. In FPL's next depreciation study, the Company shall provide specific information supporting a shorter life span, if it believes that to be appropriate.

No party disputed FPL's proposed life spans of 60 years for its nuclear units, except OPC believed that the life spans should match the actual license termination date of each unit. We agree. Also, no party disputed FPL's proposed life spans for its combustion turbines. Accordingly, we believe that they are appropriate.

2. Interim Retirements

OPC witness Pous agreed that interim retirements should be included in the calculation of production plant lives, but disagreed with FPL's approach in estimating interim retirements. OPC proposed constant interim retirement rates based on a method sponsored by the California Public Utilities Commission[19] and recognized by the National Association of Regulatory Utility Commissioners (NARUC).[20] The witness explained that he developed interim retirement ratios based on actual FPL historical retirements for each production account.

On the other hand, FPL contended that a constant interim retirement rate approach did not accurately estimate expected interim activity because the approach assumes a constant level of retirements throughout the group of investment's life rather than increased retirements as the property ages. Moreover, FPL asserted that OPC's interim retirement rates were only based on a single observed data point, rather than multiple data points as OPC claimed. FPL claimed that OPC's constant retirement rate calculation was mathematically incorrect and ignored later data points that have experienced higher levels of retirements. Finally, FPL contended that a constant retirement rate assumed that future interim retirement activity will be the same as past retirement activity, which is unlikely. FPL noted that things such as cap-and-trade legislation could require large investments in new technologies and lead to associated retirements to meet future regulatory requirements.

We have previously found that a generating station, or a generating unit, can be looked at as a box containing an assortment of various types of assets which can be expected to experience varied lives.[21] Prior to this current depreciation study, FPL utilized its mechanized property record system to provide in-depth stratified information for the assets in an account at a specific

[19] Determination of Straight-Line Remaining Life Depreciation Accruals Standard Practice U-4.
[20] Public Utility Depreciation Practices.
[21] Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company, p. 4.

unit.[22] The life of the account was then arrived at by compositing expectations of the various strata.

In the current study, FPL did not use a stratified approach in determining production plant lives, but rather used a curve-life combination to depict interim retirements. In our opinion, such an approach leads to much more subjectivity than the stratification approach. Also, FPL's method of estimating interim retirements in its current depreciation study is not simpler than its previously used approach, especially given that the stratified information is contained in FPL's mechanized property record system. However, with any stratification, we recognize that the degree of disaggregation should be tempered by the associated costs.

We note that both FPL's method and OPC's method of determining interim retirements are industry acceptable practices. We agree with FPL's criticism that OPC's use of a constant retirement rate assumes that retirements in the future will mirror those of the past. However, it also appears that FPL based its selected life and curve combinations on a statistical analysis of historical data. The evidence does not indicate how, if at all, future expectations were considered in FPL's curve selections.

Based on the record evidence presented, we calculated a constant retirement rate based on the data provided in FPL's original observed data for each account. The interim retirement rates we use in this proceeding are contained in Table 2, on the following page.

[22] Stratification is the determination that a given account at a specific generating unit contains a certain amount of investment in such things as pumps, piping, rotors, or structures, with each strata expected to have a certain service life.

Table 2: Commission Approved Interim Retirement Rates	
Account	Interim Retirement Rate
Steam Production	
311 – Structures & Improvements	0.0032
312 – Boiler Plant Equipment	0.0094
314 – Turbogenerator Units	0.0120
315 – Accessory Electric Equipment	0.0052
316 – Misc. Power Plant Equipment	0.0071
Nuclear Production	
321 – Structures & Improvements	0.0028
322 – Reactor Plant Equipment	0.0056
323 – Turbogenerator Units	0.0138
324 – Accessory Electric Equipment	0.0012
325 – Misc. Power Plant Equipment	0.0032
Other Production	
341 – Structures & Improvements	0.0023
342 – Fuel Holders, Producers & Accessories	0.0095
343* - Prime Movers	0.0057
344 – Turbogenerator Units	0.0016
345 – Accessory Electric Equipment	0.0013
346 – Misc. Power Plant Equipment	0.0026

* An interim retirement rate of 0.1565 is recommended for capitalized spare parts.

We applied the interim retirement rate to the overall life span of the generating unit to determine an average service life and average remaining life. Our approved average remaining lives are contained in Table 3, below.

3. Interim Net Salvage

OPC witness Pous claimed that FPL's proposed interim net salvage parameters were excessively negative. OPC witness Pous contended that FPL failed to determine whether any activity in any particular year of its analysis was representative of the remaining investment. The witness proposed adjustments for two steam production accounts, two nuclear accounts, and five other production accounts.

In contrast to OPC's proposed interim net salvage proposals, FPL asserted that interim net salvage was developed for each account using a combination of historical data and informed judgment. The Company averred that, because interim net salvage did not pertain to all of the property, it adjusted the net salvage percent based on the percentage of plant that will be retired as interim retirements.

3a. Account-Specific Net Salvage Analysis

3a1. Steam Production

Account 311 – Structures and Improvements

FPL's currently approved interim net salvage for this account is negative 9 percent. FPL proposed net salvage of negative 15 percent, adjusted to negative 5 percent for interim retirements. Witness Clarke asserted that the historical data had averaged negative 15 percent with recent cost of removal increasing.

OPC proposed interim net salvage of negative 5 percent, reduced to zero for interim retirements. Witness Pous contended that FPL ignored recent activity indicating about negative 10 percent net salvage to a positive net salvage. Additionally, he noted that a disproportionate share of the historical retirements in this account have been piping, and replacement of a retaining wall and a cooling pond underdrain system, that may not be indicative of the future. Because piping comprised only 16 percent of the account's investment, the OPC witness asserted that it was given too much weight in FPL's analysis.

Based on the record evidence, we believe a negative 10 percent net salvage is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3, below.

Account 312 – Boiler Plant Equipment

The currently approved interim net salvage for this account is negative 6 percent. FPL asserted that cost of removal had increased over the past few years indicating the need to increase the negative net salvage. Historical salvage data for the 1986-2007 period averaged negative 27 percent, with the 2005-2007 band averaging negative 15 percent. The Company proposed a net salvage of negative 15 percent, adjusted to negative 11 percent for interim retirements. Based on the record evidence, we believe FPL's net salvage proposal is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3 below.

Account 314 – Turbogenerator Units

FPL's currently approved interim net salvage for this account is negative 6 percent. FPL proposed an interim net salvage of zero, noting that salvage data had been erratic.

OPC proposed positive 10 percent net salvage, adjusted to 1.67 percent for interim retirements. OPC contended that FPL's approach to this account was inconsistent with its approach in other accounts because it did not recognize that this account has historically averaged 8 percent positive net salvage, or that the five-year band of data reflected positive 9 percent.

Salvage activity has historically averaged positive 8 percent. The most recent two-year band averaged negative 11 percent. We agree with FPL that the data is erratic. Net salvage has ranged from negative 264 percent to positive 218 percent. Given that such wide variances do not indicate a consistent pattern, we approve the interim net salvage values shown in Table 3.

Account 315 – Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 6 percent. FPL proposed increasing the negative net salvage to negative 20 percent to recognize increased costs of removal. The five-year band of salvage data averaged negative 28 percent with a number of years over 30 percent. Adjusted for interim retirements, FPL proposed negative 12 percent net salvage. OPC did not address FPL's proposal.

Net salvage has historically averaged negative 19 percent, with the most recent three-year and four-year bands average negative 28 percent. Based on the record evidence, we believe the Company's proposed net salvage value is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3.

Account 316 – Miscellaneous Equipment

The currently approved interim net salvage for this account is zero percent. FPL noted that while the net salvage amounts were not large, cost of removal tended to be greater than realized gross salvage. Accordingly, FPL proposed negative 5 percent net salvage, adjusted to negative 4 percent for interim retirements. OPC did not address FPL's net salvage proposal for this account.

Historically, net salvage for this account has averaged negative 5 percent with the most recent five years average negative 8 percent. This account has not experienced sufficient retirements on which to rely. For this reason, we approve the interim net salvage values shown in Table 3.

3a2. Nuclear Production

Account 321 – Structures and Improvements

The currently approved interim net salvage for this account is negative 1 percent. Historically, net salvage averaged positive 8 percent, with some years being positive and some years being negative. FPL proposed a zero net salvage based on the erratic behavior of the data. OPC did not address FPL's proposal. Based on the account activity, we approve the Company's proposed net salvage.

Account 322 – Reactor Plant Equipment

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed net salvage of negative 5 percent, adjusted to negative 4 percent for interim retirements.

OPC proposed retaining the current negative 2 percent interim net salvage. OPC explained that FPL recognized that the currently approved interim net salvage appeared justified, absent recent years in which there were some large retirements that distorted the activity. Nonetheless, the Company proposed an increase in the interim net salvage until more data was available. OPC contended that FPL's reasoning for its proposed net salvage was inconsistent with its approach in other accounts that also indicated positive net salvage, where FPL selected zero until a pattern was established.

Historically, net salvage has averaged negative 11 percent with recent years being more negative, in part due to the retirements associated with the uprate project. Discounting those years, net salvage has averaged slightly negative. Based on the record evidence, we are hesitant to approve a higher negative net salvage. Accordingly, we approve the currently approved net salvage of negative 2 percent.

Account 323 – Turbogenerator Units

The currently approved interim net salvage is negative 4 percent. FPL proposed a zero percent net salvage. The Company explained that the historical data showed positive net salvage in some years and negative net salvage in other years. Large retirements in recent years realized both high gross salvage and high removal costs. Until it is determined whether this type of activity will continue, FPL proposed zero percent net salvage. Based on the data for this account, we approve zero percent net salvage.

Account 324 – Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed increasing net salvage to negative 20 percent, adjusted to negative 18 percent for interim retirements. The Company stated that retirements had been fairly consistent with cost of removal always exceeding gross salvage. Historical data averaged negative 19 percent with the past five years of net salvage data averaging negative 41 percent.

OPC proposed negative 2 percent negative net salvage, adjusted to negative 0.06 percent for interim retirements. OPC asserted that the most recent five-year band of data represented less than 1 percent of retirement activity, rendering the results meaningless. We agree and, therefore, approve the currently approved interim net salvage of negative 2 percent.

Account 325 – Miscellaneous Power Plant Equipment

The currently approved net salvage for this account is negative 1 percent. FPL proposed zero interim net salvage based on the fact that historical data indicated positive net salvage with only the past couple of years showing cost of removal exceeding gross salvage. Based on the record evidence, we find that FPL's proposal is reasonable.

3a3. Other Production

Account 341 – Structures & Improvements

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed increasing net salvage to negative 25 percent to reflect increasing removal costs. Adjusting for interim retirements, a negative 12 percent interim net salvage resulted.

OPC proposed interim net salvage of zero. OPC asserted that while FPL recognized increased removal costs, it discounted the 2007 positive net salvage as an anomaly without any investigation.

Historical net salvage for this account has averaged negative 20 percent, with the most recent five-year band averaging positive 9 percent. There was no indication from FPL why the removal costs incurred in 2005 should not be considered an anomaly. We approve the negative 2 percent interim net salvage for this account until more data is available.

Account 342 – Other Production Fuel Holders

The currently approved interim net salvage for this account is zero percent. FPL proposed interim net salvage of negative 5 percent to reflect increased removal costs. Adjusting for interim retirements resulted in negative 3 percent interim net salvage. The Company asserted that the account retirements have been erratic. However, when retirements have occurred, cost of removal with little gross salvage was experienced.

OPC proposed interim net salvage of zero. OPC viewed FPL's proposal as unwarranted given the lack of retirement data.

Based on the record evidence, this account shows insufficient retirements upon which to draw a meaningful conclusion. Accordingly, we approve the currently approved zero percent interim net salvage.

Account 343 – Other Production Prime Movers

The currently approved interim net salvage for this account is zero. FPL proposed interim net salvage of negative 10 percent adjusted to negative 2 percent for interim retirements. FPL asserted that historical net salvage averaged negative 24 percent, with the most recent five years averaging negative 14 percent. The Company averred that this data warranted an increase in negative net salvage.

OPC proposed interim net salvage of zero. OPC asserted that FPL's data included two large negative gross salvage amounts. This data caused the historical information to be excessively negative and produced illogical results. OPC averred that if this data is removed as an anomaly, there is no basis for changing the currently approved interim net salvage.

We agree with OPC that negative gross salvage amounts are illogical. We also agree with FPL that even ignoring these amounts, net salvage has been negative. FPL proposed zero

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net salvage in its 2005 depreciation study when the data showed negative net salvage. Therefore, we are hard pressed to approve a net salvage more negative when nothing has essentially changed since the 2005 depreciation analysis. We therefore approve the currently prescribed zero percent interim net salvage.

Account 344 – Other Production Generators

The currently approved interim net salvage for this account is negative 1 percent. FPL proposed a negative 100 percent net salvage based on the most recent five years of data, adjusted to negative 11 percent for interim retirements.

OPC proposed zero net salvage. OPC asserted that FPL had not adequately explained or supported its proposal.

Historical net salvage has averaged negative 98 percent, with the most recent five years of data averaging negative net salvage in excess of 100 percent. We note that retirements during the past five years account for more than 60 percent of all retirements recorded during the 1987-2007 period. We also note that until the last five years, cost of removal as well as retirements had generally been negligible. FPL did not explain what caused the sudden increase in activity, so we are unable to verify if its proposed net salvage is appropriate. Under the circumstances, we approve the currently approved interim net salvage of negative 1 percent.

Account 345 – Other Production Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 1 percent. FPL proposed increasing net salvage to negative 10 percent, adjusted to negative 3 percent for interim retirements. The Company states that its proposal is in line with the historical net salvage experience of the account.

OPC proposed zero percent interim net salvage. OPC asserted that the retirement activity during the past five years represented less than 0.4 percent of the account's investment, and 79 percent of that activity was associated with items such as batteries and battery chargers that represented less than 5 percent of the account's investment. Thus, OPC contended that FPL's proposed interim negative net salvage was overstated.

Historical net salvage has averaged negative 7 percent with the most recent five-year band of data averaging negative 14 percent. FPL contended that OPC's argument was flawed because the account's retirements reflect the types of property that will likely be retired interimly and not necessarily the same investment mix. However, FPL did not explain other types of investments subject to interim retirement or the type of salvage they were likely to incur. It is difficult to assume that past activity is indicative of the future if the past is not representative of the type of activity being estimated. For this reason, we approve the currently prescribed negative 1 percent interim net salvage.

Account 346 – Miscellaneous Power Plant Equipment

The currently approved interim net salvage is zero percent, which FPL proposed retaining. Historical net salvage as well has the most recent five years of data have averaged negative 2 percent. Retirements have been minimal. Based on the record evidence, we find FPL's proposal reasonable.

4. Amortizations

In accord with Rule 25-6.0142, F.A.C., FPL amortizes investments in the miscellaneous power plant accounts that represent minor investments of numerous items that are too numerous to track or trace. Each vintage year's additions associated with each account is amortized over a like period of time. FPL proposed no change to these amortizations and none of the intervenors disputed them.

5. Conclusion

The approved depreciation parameters and resulting depreciation rates for production plant are shown on Table 3, on the following pages. The reserve positions shown incorporate the effects of the approved reserve allocations addressed below.

Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
CUTLER PLANT				
Cutler Common				
311.0 Structures & Improvements	10.3	(2.00)	84.49	1.7
312.0 Boiler Plant Equipment	9.9	(7.00)	85.38	2.2
314.0 Turbogenerator Units	9.8	0.00	78.22	2.2
315.0 Accessory Electric Equip.	10.2	(6.00)	86.69	1.9
316.0 Misc. Power Plant Equip.	10.1	0.00	80.94	1.9
Cutler Unit 5				
311.0 Structures & Improvements	10.3	(2.00)	84.49	1.7
312.0 Boiler Plant Equipment	9.9	(7.00)	85.38	2.2
314.0 Turbogenerator Units	9.8	0.00	78.22	2.2
315.0 Accessory Electric Equip.	10.2	(6.00)	86.69	1.9
316.0 Misc. Power Plant Equip.	10.1	0.00	80.94	1.9
Cutler Unit 6				
311.0 Structures & Improvements	10.3	(2.00)	84.49	1.7
312.0 Boiler Plant Equipment	9.9	(7.00)	85.38	2.2
314.0 Turbogenerator Units	9.8	0.00	78.22	2.2
315.0 Accessory Electric Equip.	10.2	(6.00)	86.69	1.9
316.0 Misc. Power Plant Equip.	10.1	0.00	80.94	1.9

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
MANATEE PLANT				
Manatee Common				
311.0 Structures & Improvements	17	(1.00)	64.47	2.1
312.0 Boiler Plant Equipment	16.1	(2.00)	60.95	2.6
314.0 Turbogenerator Units	15.7	0.00	58.68	2.6
315.0 Accessory Electric Equip.	16.7	(5.00)	65.15	2.4
316.0 Misc. Power Plant Equip.	16.4	(1.00)	61.56	2.4
Manatee Unit 1				
311.0 Structures & Improvements	17	(1.00)	64.47	2.1
312.0 Boiler Plant Equipment	16.1	(2.00)	60.95	2.6
314.0 Turbogenerator Units	15.7	0.00	58.68	2.6
315.0 Accessory Electric Equip.	16.7	(5.00)	65.15	2.4
316.0 Misc. Power Plant Equip.	16.4	(1.00)	61.56	2.4
Manatee Unit 2				
311.0 Structures & Improvements	17	(1.00)	64.47	2.1
312.0 Boiler Plant Equipment	16.1	(2.00)	60.95	2.6
314.0 Turbogenerator Units	15.7	0.00	58.68	2.6
315.0 Accessory Electric Equip.	16.7	(5.00)	65.15	2.4
316.0 Misc. Power Plant Equip.	16.4	(1.00)	61.56	2.4

Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
MARTIN PLANT				
Martin Common				
311.0 Structures & Improvements	21	(1.00)	55.87	2.1
312.0 Boiler Plant Equipment	19.4	(5.00)	54.08	2.6
314.0 Turbogenerator Units	18.8	0.00	50.53	2.6
315.0 Accessory Electric Equip.	20	(5.00)	57.27	2.4
316.0 Misc. Power Plant Equip.	19.9	0.00	52.62	2.4
Martin Pipeline				
312.0 Boiler Plant Equipment	19.4	(5.00)	54.08	2.6
Martin Unit 1				
311.0 Structures & Improvements	21	(1.00)	55.87	2.1
312.0 Boiler Plant Equipment	19.4	(5.00)	54.08	2.6
314.0 Turbogenerator Units	18.8	0.00	50.53	2.6
315.0 Accessory Electric Equip.	20	(5.00)	57.27	2.4
316.0 Misc. Power Plant Equip.	19.9	0.00	52.62	2.4
Martin Unit 2				
311.0 Structures & Improvements	21	(1.00)	55.87	2.1
312.0 Boiler Plant Equipment	19.4	(5.00)	54.08	2.6
314.0 Turbogenerator Units	18.8	0.00	50.53	2.6
315.0 Accessory Electric Equip.	20	(5.00)	57.27	2.4
316.0 Misc. Power Plant Equip.	19.9	0.00	52.62	2.4

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
PT EVERGLADES PLANT				
Pt Everglades Common				
311.0 Structures & Improvements	10.3	(2.00)	82.90	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	83.19	2.3
314.0 Turbogenerator Units	9.8	0.00	77.21	2.3
315.0 Accessory Electric Equip.	10.2	(5.00)	84.40	2.0
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.98	2.1
Pt Everglades Unit 1				
311.0 Structures & Improvements	10.3	(2.00)	82.90	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	83.19	2.3
314.0 Turbogenerator Units	9.8	0.00	77.21	2.3
315.0 Accessory Electric Equip.	10.2	(5.00)	84.40	2.0
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.98	2.1
Pt Everglades Unit 2				
311.0 Structures & Improvements	10.3	(2.00)	82.90	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	83.19	2.3
314.0 Turbogenerator Units	9.8	0.00	77.21	2.3
315.0 Accessory Electric Equip.	10.2	(5.00)	84.40	2.0
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.98	2.1
Pt Everglades Unit 3				
311.0 Structures & Improvements	10.3	(2.00)	82.90	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	83.19	2.3
314.0 Turbogenerator Units	9.8	0.00	77.21	2.3
315.0 Accessory Electric Equip.	10.2	(5.00)	84.40	2.0
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.98	2.1
Pt Everglades Unit 4				
311.0 Structures & Improvements	10.3	(2.00)	82.90	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	83.19	2.3
314.0 Turbogenerator Units	9.8	0.00	77.21	2.3
315.0 Accessory Electric Equip.	10.2	(5.00)	84.40	2.0
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.98	2.1

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Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
SANFORD PLANT				
Sanford Unit 3				
311.0 Structures & Improvements	10.3	(2.00)	82.54	1.9
312.0 Boiler Plant Equipment	9.9	(6.00)	82.68	2.4
314.0 Turbogenerator Units	9.8	0.00	76.67	2.4
315.0 Accessory Electric Equip.	10.2	(5.00)	84.00	2.1
316.0 Misc. Power Plant Equip.	10.1	(2.00)	80.54	2.1

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
SCHERER PLANT				
Scherer Coal Cars				
312.0 Boiler Plant Equipment	26	(5.00)	36.75	2.6
Scherer Common (Site)				
311.0 Structures & Improvements	28	(1.00)	40.83	2.1
312.0 Boiler Plant Equipment	26	(5.00)	36.75	2.6
314.0 Turbogenerator Units	25	0.00	34.21	2.6
315.0 Accessory Electric Equip.	27	(4.00)	40.18	2.4
316.0 Misc. Power Plant Equip.	27	(1.00)	36.07	2.4
Scherer Common 3 & 4				
311.0 Structures & Improvements	28	(1.00)	41.23	2.2
312.0 Boiler Plant Equipment	26	(5.00)	37.10	2.7
314.0 Turbogenerator Units	25	0.00	34.21	2.6
315.0 Accessory Electric Equip.	27	(4.00)	40.57	2.4
Scherer Unit 4				
311.0 Structures & Improvements	28	(1.00)	40.83	2.1
312.0 Boiler Plant Equipment	26	(5.00)	36.75	2.6
314.0 Turbogenerator Units	25	0.00	34.21	2.6
315.0 Accessory Electric Equip.	27	(4.00)	40.18	2.4
316.0 Misc. Power Plant Equip.	27	(1.00)	36.07	2.4

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Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
SJRPP PLANT				
SJRPP Coal Cars				
312.0 Boiler Plant Equipment	26	(5.00)	36.75	2.6
SJRPP Coal & Limestone				
311.0 Structures & Improvements	28	(1.00)	40.83	2.1
312.0 Boiler Plant Equipment	26	(5.00)	36.75	2.6
315.0 Accessory Electric Equip.	27	(4.00)	40.18	2.4
316.0 Misc. Power Plant Equip.	27	(1.00)	36.07	2.4
SJRPP Common				
311.0 Structures & Improvements	27	(1.00)	42.98	2.1
312.0 Boiler Plant Equipment	25	(5.00)	39.38	2.6
315.0 Accessory Electric Equip.	26	(4.00)	42.55	2.4
316.0 Misc. Power Plant Equip.	26	(1.00)	38.48	2.4
SJRPP Gypsum & Ash				
311.0 Structures & Improvements	27	(1.00)	42.98	2.1
312.0 Boiler Plant Equipment	25	(5.00)	39.38	2.6
314.0 Turbogenerator Units		0.00	36.84	2.6
315.0 Accessory Electric Equip.	26	(4.00)	42.55	2.4
316.0 Misc. Power Plant Equip.	26	(1.00)	38.48	2.4
SJRPP Unit 1				
311.0 Structures & Improvements	27	(1.00)	42.98	2.1
312.0 Boiler Plant Equipment	25	(5.00)	39.38	2.6
314.0 Turbogenerator Units	24	0.00	36.84	2.6
315.0 Accessory Electric Equip.	26	(4.00)	42.55	2.4
316.0 Misc. Power Plant Equip.	26	(1.00)	38.48	2.4
SJRPP Unit 2				
311.0 Structures & Improvements	27	(1.00)	42.98	2.1
312.0 Boiler Plant Equipment	25	(5.00)	39.38	2.6
314.0 Turbogenerator Units	24	0.00	36.84	2.6
315.0 Accessory Electric Equip.	26	(4.00)	42.55	2.4
316.0 Misc. Power Plant Equip.	26	(1.00)	38.48	2.4

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
TURKEY POINT PLANT				
Turkey Point Common				
311.0 Structures & Improvements	10.3	(2.00)	80.56	2.1
312.0 Boiler Plant Equipment	9.9	(6.00)	81.01	2.5
314.0 Turbogenerator Units	9.8	0.00	74.87	2.6
315.0 Accessory Electric Equip.	10.2	(5.00)	82.21	2.2
316.0 Misc.Power Plant Equip.	10.1	(2.00)	78.59	2.3
Turkey Point Unit 1				
311.0 Structures & Improvements	10.3	(2.00)	80.56	2.1
312.0 Boiler Plant Equipment	9.9	(6.00)	81.01	2.5
314.0 Turbogenerator Units	9.8	0.00	74.87	2.6
315.0 Accessory Electric Equip.	10.2	(5.00)	82.21	2.2
316.0 Misc.Power Plant Equip.	10.1	(2.00)	78.59	2.3
Turkey Point Unit 2				
311.0 Structures & Improvements	10.3	(2.00)	80.56	2.1
312.0 Boiler Plant Equipment	9.9	(6.00)	81.01	2.5
314.0 Turbogenerator Units	9.8	0.00	74.87	2.6
315.0 Accessory Electric Equip.	10.2	(5.00)	82.21	2.2
316.0 Misc.Power Plant Equip.	10.1	(2.00)	78.59	2.3

Table 3: Approved Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
ST LUCIE PLANT				
St Lucie Common				
321.0 Structures & Improvements	32	0.00	42.86	1.8
322.0 Reactor Plant Equipment	30	(2.00)	42.00	2.0
323.0 Turbogenerator Units	27	0.00	34.15	2.4
324.0 Accessory Electric Equip.	33	(2.00)	43.97	1.8
325.0 Misc.Power Plant Equip.	32	0.00	41.82	1.8
St Lucie Unit 1				
321.0 Structures & Improvements	26	0.00	53.57	1.8
322.0 Reactor Plant Equipment	25	(2.00)	52.00	2.0
323.0 Turbogenerator Units	22	0.00	46.34	2.4
324.0 Accessory Electric Equip.	26	(2.00)	56.28	1.8
325.0 Misc.Power Plant Equip.	25	0.00	54.55	1.8
St Lucie Unit 2				
321.0 Structures & Improvements	32	0.00	42.86	1.8
322.0 Reactor Plant Equipment	30	(2.00)	42.00	2.0
323.0 Turbogenerator Units	27	0.00	34.15	2.4
324.0 Accessory Electric Equip.	33	(2.00)	43.97	1.8
325.0 Misc.Power Plant Equip.	32	0.00	41.82	1.8

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Table 3: Approved Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED			
	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
TURKEY POINT PLANT				
Turkey Point Common				
321.0 Structures & Improvements	23	0.00	58.93	1.8
322.0 Reactor Plant Equipment	22	(2.00)	58.00	2.0
323.0 Turbogenerator Units	19.9	0.00	51.46	2.4
324.0 Accessory Electric Equip.	23	(2.00)	61.55	1.8
325.0 Misc.Power Plant Equip.	23	0.00	58.18	1.8
Turkey Point Unit 3				
321.0 Structures & Improvements	23	0.00	58.93	1.8
322.0 Reactor Plant Equipment	22	(2.00)	58.00	2.0
323.0 Turbogenerator Units	19.9	0.00	51.46	2.4
324.0 Accessory Electric Equip.	23	(2.00)	61.55	1.8
325.0 Misc.Power Plant Equip.	23	0.00	58.18	1.8
Turkey Point Unit 4				
321.0 Structures & Improvements	23	0.00	58.93	1.8
322.0 Reactor Plant Equipment	22	(2.00)	58.00	2.0
323.0 Turbogenerator Units	19.9	0.00	51.46	2.4
324.0 Accessory Electric Equip.	23	(2.00)	61.55	1.8
325.0 Misc.Power Plant Equip.	23	0.00	58.18	1.8

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
FT MYERS PLANT				
Ft Myers Common				
341.0 Structures & Improvements	23	(2.00)	21.10	3.5
342.0 Fuel Holders, Prod. & Access.	21	0.00	19.23	3.8
343.0 Prime Movers	13.9	0.00	18.71	5.8
344.0 Turbogenerator Units	23	(1.00)	23.57	3.4
345.0 Accessory Electric Equipment	23	(1.00)	23.57	3.4
346.0 Misc. Power Plant Equipment	23	0.00	20.69	3.4
Ft Myers Unit 2				
341.0 Structures & Improvements	22	(2.00)	24.62	3.5
342.0 Fuel Holders, Prod. & Access.	20	0.00	23.08	3.8
343.0 Prime Movers	18	0.00	25.00	4.2
344.0 Turbogenerator Units	22	(1.00)	26.93	3.4
345.0 Accessory Electric Equipment	22	(1.00)	26.93	3.4
346.0 Misc. Power Plant Equipment	22	0.00	24.14	3.4
Ft Myers Unit 3 (Simple Cycle)				
341.0 Structures & Improvements	23	(2.00)	21.10	3.5
342.0 Fuel Holders, Prod. & Access.	21	0.00	19.23	3.8
343.0 Prime Movers	15.5	0.00	18.85	5.2
344.0 Turbogenerator Units	23	(1.00)	23.57	3.4
345.0 Accessory Electric Equipment	23	(1.00)	23.57	3.4
346.0 Misc. Power Plant Equipment	23	0.00	20.69	3.4
Ft Myers GTs				
341.0 Structures & Improvements	10.4	(2.00)	77.89	2.3
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	73.24	2.7
343.0 Prime Movers	8.7	0.00	72.81	3.1
344.0 Turbogenerator Units	10.4	(1.00)	77.66	2.2
345.0 Accessory Electric Equipment	10.4	(1.00)	77.66	2.2
346.0 Misc. Power Plant Equipment	10.3	0.00	76.59	2.3

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
LAUDERDALE PLANT				
Lauderdale Common				
341.0 Structures & Improvements	13.3	(2.00)	55.22	3.5
342.0 Fuel Holders, Prod. & Access.	12.6	0.00	51.54	3.8
343.0 Prime Movers	8.9	0.00	47.02	6.0
344.0 Turbogenerator Units	13.3	(1.00)	56.22	3.4
345.0 Accessory Electric Equipment	13.4	(1.00)	55.89	3.4
346.0 Misc. Power Plant Equipment	13.2	0.00	54.48	3.4
Lauderdale Unit 4				
341.0 Structures & Improvements	13.3	(2.00)	55.22	3.5
342.0 Fuel Holders, Prod. & Access.	12.6	0.00	51.54	3.8
343.0 Prime Movers	11.2	0.00	51.30	4.3
344.0 Turbogenerator Units	13.3	(1.00)	56.22	3.4
345.0 Accessory Electric Equipment	13.4	(1.00)	55.89	3.4
346.0 Misc. Power Plant Equipment	13.2	0.00	54.48	3.4
Lauderdale Unit 5				
341.0 Structures & Improvements	13.3	(2.00)	55.22	3.5
342.0 Fuel Holders, Prod. & Access.	12.6	0.00	51.54	3.8
343.0 Prime Movers	11.5	0.00	52.08	4.2
344.0 Turbogenerator Units	13.3	(1.00)	56.22	3.4
345.0 Accessory Electric Equipment	13.4	(1.00)	55.89	3.4
346.0 Misc. Power Plant Equipment	13.2	0.00	54.48	3.4
Lauderdale GTs				
341.0 Structures & Improvements	10.4	(2.00)	79.43	2.2
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	74.62	2.6
343.0 Prime Movers	8.9	0.00	73.82	2.9
344.0 Turbogenerator Units	10.4	(1.00)	79.12	2.1
345.0 Accessory Electric Equipment	10.4	(1.00)	79.12	2.1
346.0 Misc. Power Plant Equipment	10.3	0.00	77.61	2.2

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED			
	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
Pt Everglades GTs				
341.0 Structures & Improvements	10.4	(2.00)	79.43	2.2
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	74.62	2.6
343.0 Prime Movers	8.2	0.00	71.72	3.4
344.0 Turbogenerator Units	10.4	(1.00)	79.12	2.1
345.0 Accessory Electric Equipment	10.4	(1.00)	79.12	2.1
346.0 Misc. Power Plant Equipment	10.3	0.00	77.61	2.2
MANATEE PLANT				
Manatee Unit 3				
341.0 Structures & Improvements	25	(2.00)	14.07	3.5
342.0 Fuel Holders, Prod. & Access.	23	0.00	11.54	3.8
343.0 Prime Movers	20	0.00	13.04	4.3
344.0 Turbogenerator Units	25	(1.00)	16.83	3.4
345.0 Accessory Electric Equipment	25	(1.00)	16.83	3.4
346.0 Misc. Power Plant Equipment	25	0.00	13.79	3.4

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
MARTIN PLANT				
Martin Common				
341.0 Structures & Improvements	14.2	(2.00)	52.06	3.5
342.0 Fuel Holders, Prod. & Access.	13.5	0.00	48.08	3.8
343.0 Prime Movers	12.0	0.00	47.83	4.3
345.0 Accessory Electric Equipment	14.4	(1.00)	52.52	3.4
346.0 Misc. Power Plant Equipment	14.2	0.00	51.03	3.4
Martin Pipeline				
342.0 Fuel Holders, Prod. & Access.	13.5	0.00	48.08	3.8
Martin Unit 3				
341.0 Structures & Improvements	14.2	(2.00)	52.06	3.5
342.0 Fuel Holders, Prod. & Access.	13.5	0.00	48.08	3.8
343.0 Prime Movers	12.5	0.00	47.92	4.2
344.0 Turbogenerator Units	14.3	(1.00)	52.86	3.4
345.0 Accessory Electric Equipment	14.4	(1.00)	52.52	3.4
346.0 Misc. Power Plant Equipment	14.2	0.00	51.03	3.4
Martin Unit 4				
341.0 Structures & Improvements	14.2	(2.00)	52.06	3.5
342.0 Fuel Holders, Prod. & Access.	13.5	0.00	48.08	3.8
343.0 Prime Movers	12.4	0.00	48.33	4.2
344.0 Turbogenerator Units	14.3	(1.00)	52.86	3.4
345.0 Accessory Electric Equipment	14.4	(1.00)	52.52	3.4
346.0 Misc. Power Plant Equipment	14.2	0.00	51.03	3.4
Martin Unit 8				
341.0 Structures & Improvements	25	(2.00)	14.07	3.5
342.0 Fuel Holders, Prod. & Access.	23	0.00	11.54	3.8
343.0 Prime Movers	20	0.00	13.04	4.3
344.0 Turbogenerator Units	25	(1.00)	16.83	3.4
345.0 Accessory Electric Equipment	25	(1.00)	16.83	3.4
346.0 Misc. Power Plant Equipment	24	0.00	17.24	3.4

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Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
PUTNAM PLANT				
Putnam Common				
341.0 Structures & Improvements	10.4	(2.00)	75.48	2.6
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	71.71	2.9
343.0 Prime Movers	7.7	0.00	67.92	4.2
344.0 Turbogenerator Units	10.4	(1.00)	75.38	2.5
345.0 Accessory Electric Equipment	10.4	(1.00)	75.38	2.5
346.0 Misc. Power Plant Equipment	10.3	0.00	74.25	2.5
Putnam Unit 1				
341.0 Structures & Improvements	10.4	(2.00)	75.48	2.6
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	71.71	2.9
343.0 Prime Movers	7.9	0.00	68.40	4.0
344.0 Turbogenerator Units	10.4	(1.00)	75.38	2.5
345.0 Accessory Electric Equipment	10.4	(1.00)	75.38	2.5
346.0 Misc. Power Plant Equipment	10.3	0.00	74.25	2.5
Putnam Unit 2				
341.0 Structures & Improvements	10.4	(2.00)	76.13	2.5
342.0 Fuel Holders, Prod. & Access.	9.9	0.00	71.71	2.9
343.0 Prime Movers	8.6	0.00	71.33	3.3
344.0 Turbogenerator Units	10.4	(1.00)	75.99	2.4
345.0 Accessory Electric Equipment	10.4	(1.00)	75.99	2.4
346.0 Misc. Power Plant Equipment	10.3	0.00	74.88	2.4

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
SANFORD PLANT				
Sanford Common				
341.0 Structures & Improvements	22	(2.00)	24.62	3.5
342.0 Fuel Holders, Prod. & Access.	20	0.00	23.08	3.8
343.0 Prime Movers	17.8	0.00	19.09	4.5
345.0 Accessory Electric Equipment	22	(1.00)	26.93	3.4
346.0 Misc. Power Plant Equip.	22	0.00	24.14	3.4
Sanford Unit 4				
341.0 Structures & Improvements	23	(2.00)	21.10	3.5
342.0 Fuel Holders, Prod. & Access.	21	0.00	19.23	3.8
343.0 Prime Movers	16.8	0.00	20.00	4.8
344.0 Turbogenerator Units	23	(1.00)	23.57	3.4
345.0 Accessory Electric Equipment	23	(1.00)	23.57	3.4
346.0 Misc. Power Plant Equip.	23	0.00	20.69	3.4
Sanford Unit 5				
341.0 Structures & Improvements	22	(2.00)	24.62	3.5
342.0 Fuel Holders, Prod. & Access.	20	0.00	23.08	3.8
343.0 Prime Movers	18.1	0.00	24.58	4.2
344.0 Turbogenerator Units	22	(1.00)	26.93	3.4
345.0 Accessory Electric Equipment	22	(1.00)	26.93	3.4
346.0 Misc. Power Plant Equip.	22	0.00	24.14	3.4

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Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
TURKEY POINT				
Turkey Point Unit 5				
341.0 Structures & Improvements	27	(2.00)	7.03	3.5
342.0 Fuel Holders, Prod. & Access.	24	0.00	7.69	3.8
343.0 Prime Movers	15.9	0.00	9.66	5.7
344.0 Turbogenerator Units	27	(1.00)	10.10	3.4
345.0 Accessory Electric Equipment	27	(1.00)	10.10	3.4
346.0 Misc. Power Plant Equip.	27	0.00	6.90	3.4

Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
WEST COUNTY PLANT				
West County Unit 1				
341.0 Structures & Improvements	30	0.00	2.56	3.3
342.0 Fuel Holders, Prod.& Access,	30	0.00	2.56	3.3
343.0 Prime Movers	30	0.00	3.50	3.3
344.0 Turbogenerator Units	30	0.00	2.50	3.3
345.0 Accessory Electric Equip.	30	0.00	3.50	3.3
West County Unit 2				
341.0 Structures & Improvements	30	0.00	2.56	3.3
342.0 Fuel Holders, Prod.& Access,	30	0.00	2.56	3.3
343.0 Prime Movers	30	0.00	3.50	3.3
344.0 Turbogenerator Units	30	0.00	2.50	3.3
345.0 Accessory Electric Equip.	30	0.00	3.50	3.3
West County Unit 3				
341.0 Structures & Improvements	30	0.00	0.00	3.3
342.0 Fuel Holders, Prod.& Access,	30	0.00	0.00	3.3
343.0 Prime Movers	30	0.00	0.00	3.3
344.0 Turbogenerator Units	30	0.00	0.00	3.3
345.0 Accessory Electric Equip.	30	0.00	0.00	3.3

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Table 3: Production Depreciation Components and Resulting Rates

	COMMISSION APPROVED			
Account Number and Description	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
SOLAR				
Desoto Solar Energy Center	30	0	0	3.3
Spacecoast Solar Energy Center	30	0	0	3.3
Martin Solar Energy Center	30	0	0	3.3

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Table 3: Production Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life (yrs.)	Net Salvage (%)	Theoretical Reserve (%)	Remaining Life Rate (%)
STEAM PRODUCTION - AMORTIZABLE				
316.3 Misc. Power Plant Equipment	3 Year Amortization			
316.5 Misc. Power Plant Equipment	5 Year Amortization			
316.7 Misc. Power Plant Equipment	7 Year Amortization			
NUCLEAR PRODUCTION - AMORTIZABLE				
325.3 Misc. Power Plant Equipment	3 Year Amortization			
325.5 Misc. Power Plant Equipment	5 Year Amortization			
325.7 Misc. Power Plant Equipment	7 Year Amortization			
OTHER PRODUCTION - AMORTIZABLE				
346.3 Misc. Power Plant Equipment	3 Year Amortization			
346.5 Misc. Power Plant Equipment	5 Year Amortization			
346.7 Misc. Power Plant Equipment	7 Year Amortization			

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Depreciation parameters and resulting rates: Transmission, Distribution, and General Accounts

In the discussion below, we address the depreciation rates for the mass property accounts, i.e., the transmission, distribution, and general accounts. Our approved depreciation parameters include the remaining life (in years), net salvage percent, and reserve percent, all of which are used to calculate the remaining life depreciation rate.[23] The reserve and any reallocations are addressed below. Based on the record, we find that adjustments to depreciation parameters in certain accounts are warranted.

For each account, FPL provided a proposal for a curve and average service life (ASL), both of which are used in the calculation of the remaining life. OPC provided proposals for curves as well as ASLs for specific accounts. Curves are denoted by a letter that describes when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL, while an R curve implies that retirements tend to occur after the ASL. The average service life denotes the average number of years that the plant within a particular account is expected to live. While the ASL may be based, at least in part on historical data, it is prospective in its outlook and implementation. The remaining life is the average number of in-service years left for plant that is currently in service. The net salvage, based on historical data but also prospective in outlook, is gross salvage minus cost of removal. The reserve percent is calculated by dividing the book reserve by the original cost of plant.

OPC and FPL disagreed on how a curve should be fitted and whether certain types of retirements should be included in the data analysis. These disagreements are found throughout the account-by-account analysis. In order to avoid repetition, these disagreements will be discussed in this part of our analysis.

OPC used visual curve fitting in its technique. OPC witness Pous asserted that data points which "reflect the most significant level of plant exposed to retirement events [exposures] —are more important . . . than others." For example, in his analysis of Account 353, Station Equipment, witness Pous contended that his proposed curve is a better fit through the first 16.5 years of age than FPL's curve, and a comparable fit to FPL's curve from 16.5 years through about 23.5 years. According to witness Pous, FPL's curve is a better fit between 23.5 and 36 years. OPC witness Pous asserted that the level of exposures is approximately $1.3 billion through the early years; however, it drops to approximately $500 million by 16.5 years of age. According to witness Pous, FPL's interpretation of the actuarial analysis is "erroneous" because it places greater significance on the end of the curve, rather than the top or head of the curve where the level of exposures is much higher.

FPL used visual curve fitting and mathematical (statistical) matching in its technique. FPL witness Clarke averred that the emphasis in curve fitting should be placed on the middle years, basing his methodology on Bulletin 125 by Robley Winfrey, "considered the dean of

[23] Both FPL and OPC recognize that depreciation involves estimates. For this reason, there is little reason to be as precise as a hundredth of a year for remaining lives. Our approved lives reflect the rounding of lives over 20 years to the nearest whole year and lives less than 20 years to the tenth of a year.

depreciation and life analysis."[24] Mr. Winfrey's recommendation is to give more weight to the middle portion of the curve, between 80 and 20 percent surviving, because this section "is the result of greater numbers of retirements and also it covers the period of most likely the normal operation of the property." Even so, according to FPL, "if the average service life and the survivor curve combination was not reasonable, experience and judgment were needed." FPL witness Clarke asserted that OPC witness Pous proposed "exactly the opposite" of what Mr. Winfrey recommends.

The disagreement on curve fitting between FPL and OPC only serves to emphasize the need for judgment. Based on the evidence, we believe that FPL's method of curve estimation, as described in the record, is appropriate because it relied on visual and mathematical curve fitting, as well as classic depreciation theory.

There is significant disagreement between FPL and OPC on whether certain data should be included or excluded when analyzing retirements and their associated cost of removal and gross salvage. When analyzing data for retirements, cost of removal, and gross salvage, FPL witness Clarke included recurring retirements that were reimbursed by outside parties. Witness Clarke, however, removed reimbursed retirements that he considered to be nonrecurring, for example, relocations required by the Department of Transportation and the installation of the new Metrorail line. Witness Clarke also removed data related to hurricanes. According to witness Clarke, hurricanes "are unexpected events that are not indicative of the future activity for an account."

OPC witness Pous did not distinguish between recurring and nonrecurring reimbursed retirements. He contended that FPL witness Clarke "removed the impact of reimbursed retirements from the analyses, even though such events occur on an annual basis . . . ." Witness Pous asserted that these reimbursed retirements "cannot legitimately be considered outliers."

In our opinion, it is reasonable to remove data related to nonrecurring events, such as hurricane effects and nonrecurring reimbursed retirements, from the analysis because the data can skew the results of the analysis. At the same time, we feel it is reasonable to include recurring data.

OPC proposed depreciation parameters for the aircraft accounts. However, there is no need at this time for us to order depreciation rates for these accounts because FPL removed aviation costs from rate base. If, in the future, FPL wishes to include aviation investment and depreciation expense in rate base for establishing revenue requirements, it will need to file a new depreciation study.

[24] Bulletin 125 was originally printed in 1935 by Iowa State University. It was revised by Harold A. Cowles, renamed the "Statistical Analyses of Industrial Property Retirements," and reprinted in April 1967.

1. Account-Specific Analysis: Transmission Plant

Account 350.20 – Easements

FPL proposed no change to its current S4 curve, 50-year average service life, and 0 percent net salvage. OPC proposed an increase in the average service life from 50 to 95 years.

OPC argued that FPL relied on "suggestive" industry data for its ASL proposal. OPC also argued that it is difficult to obtain easements for new transmission lines. This difficulty, in OPC's view, results in FPL's continued reliance on existing easements. OPC witness Pous characterized his proposal as "conservative." Witness Pous pointed out in his testimony that FPL does not have plans to retire easements.

FPL's plans are to continue to use existing easements "as it replaces transmission investment that currently occupies the easement." Although not all of FPL's easements are perpetual, FPL indicated that its "policy is to obtain perpetual rights easements (no expiration) everywhere that is available."

FPL witness Clarke asserted that there were "not many retirements in this account;" consequently, the "results of the statistical analysis were poor." According to witness Clarke, the industry range is 40-60 years, and with the present ASL of 50, "[t]here is no reason to warrant a change from the current approved [average service life of 50]." Witness Clarke characterized OPC's proposal of a 95-year ASL as "absurd." Witness Clarke averred that the maximum life of the equipment on the easements, e.g., poles, would be one half of the life of the easement.

We believe that a 50-year average service life for easements is too short, based on the evidence. OPC's arguments, for the most part, are convincing; however, not all of FPL's easements are perpetual. Therefore, we believe that a reasonable compromise is an average service life of 75 years.

Account 352.00 – Structures and Improvements

FPL proposed a change in curve from S4 to R3, an increase in the ASL from 47 to 60 years, and a decrease in net salvage from (10) percent to (15) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, both his actuarial analysis and industry data suggest a life of 50 – 60 years. Witness Clarke also asserted that both his proposed curve and ASL "are reasonable for structure of this nature, produce the best results in the life analysis and are consistent with the estimates used by other electric utilities." Both the S4 and R3 curves, with a 60-year ASL, result in approximately the same remaining life.

Witness Clarke asserted that cost of removal has increased recently; however, gross salvage is "negligible." After reviewing the data, we agree that gross salvage is negligible. Between 2000 and 2007, cost of removal ranged from 0 percent (2000) to 387 percent (2003).

Accordingly, we find that decreasing the net salvage from (10) to (15) percent appears reasonable in light of the data.

Account 353.00 – Station Equipment

FPL proposed no change in the current R1.5 curve, a two-year increase in the ASL from 36 to 38 years, and a decrease in net salvage from five percent to (10) percent. OPC proposed an L1 curve, 43-year ASL, and 0 percent net salvage.

OPC argued that FPL's curve and ASL proposal "relies on a poor and inappropriate interpretation of the results of its actuarial analysis . . . ." Witness Pous contended that his proposed curve is a better fit through the first 16.5 years, where there are the greatest level of exposures (plant available for retirement). According to FPL witness Clarke, FPL's curve was the "best fitting curve mathematically." As discussed above, we believe that FPL's curve fitting technique is the appropriate technique. Accordingly, we will use the R1.5 curve.

OPC witness Pous also asserted that with regard to the ASL, FPL witness Clarke was incorrect when he asserted that an ASL of 38-39 years is "typical." According to OPC witness Pous, an ASL of 38-39 years falls at the low end of industry data. Witness Pous contended that, based on FPL's industry data, a "typical" ASL would be 45 or 50 years. Witness Pous also asserted that although FPL claimed it recognized the trend toward longer lives, it "did not follow through." We agree with OPC that the ASL should be longer than the 38 years proposed by FPL. However, an increase from 36 to 43 years is too large an increase at one time. Therefore, based on the record evidence, we will use a compromise ASL of 40 years.

For net salvage, OPC argued that FPL's proposal is "inappropriate." According to OPC witness Pous, there are "atypical values" in FPL's data that "drive" FPL's proposal to decrease net salvage from five to (10) percent. Witness Pous also contended that FPL's proposal "fails to analyze the relationship of investment mix versus retirement mix . . . ." Witness Pous asserted that the trend of increases in the cost of removal is "significantly driven by retirements during 2007."

FPL witness Clarke asserted that OPC witness Pous "claims to have investigated these [unusual] values, but the results of his 'investigation' are in some ways bizarre." According to FPL witness Clarke, witness Pous claimed that 2007's large cost of removal "is driven by the retirement of a building with a high level of asbestos." According to witness Clarke, the type of building referred to by OPC is in another account.

While the cost of removal should be decreased, a decrease from five percent to (10) percent is too drastic. Therefore, we approve a compromise of (2) percent net salvage.

Account 353.10 – Station Equipment – Generator Step-Up Transformers

FPL proposed a change in the curve from S3 to R2, a decrease in the ASL from 35 to 33 years, and a decrease in net salvage from five to 0 percent. OPC proposed a change in the curve from S3 to S0.5 and an increase in the ASL from 35 to 44 years.

OPC argued that FPL's approach to determining an ASL is "simplistic and flawed." OPC witness Pous contended that it is "illogical and inconsistent with the historical practices for the industry" to propose a shorter life for step-up transformers than for the rest of the generation plant to which the investment in this account is "directly tied." Witness Pous also asserted that a significant retirement occurred at age zero that should have been removed from the analysis.

FPL witness Clarke's rebuttal was brief. Witness Clarke asserted that his curve and ASL proposals were based on statistical analysis. He further asserted that the "statistical analysis was good and showed a good fit . . . both graphically and mathematically." Witness Clarke contended that removing the retirement that occurred at year zero did not impact his analysis.

As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2 curve. We disagree with FPL's shortening of the ASL; however, we do not believe the record supports an increase in average service life. Therefore, we will use an ASL of 35 years.

Account 354.00 – Towers and Fixtures

FPL proposed no change to the existing R5 curve, 45-year ASL, and (15) percent net salvage. OPC proposed a small change in the curve from R5 to R4, an increase in the ASL from 45 to 60 years, and an increase in net salvage from (15) percent to 0 percent.

OPC argued that FPL admitted that the results of its actuarial analysis are "poor." OPC witness Pous asserted that OPC's "recommendation is logically derived from Company specific data, and is also reflective of what Mr. Clarke and his firm have recommended in other depreciation studies." According to witness Pous, the basis for OPC's recommendation for an R4 curve and 60-year ASL is primarily that FPL has "substantial" investment 35 years old or older and that there have been few retirements. With few retirements, OPC placed "greater reliance" on information from the industry. OPC argued that, using FPL's industry data, 63 years is the average ASL.

FPL witness Clarke contended that there was insufficient information to recommend a change to the ASL. Witness Clarke also asserted that OPC provided no evidence that the industry data results in an "appropriate comparison with FPL." Additionally, witness Clarke asserted that OPC was "wrong" about FPL having plant close to the maximum age. According to witness Clarke, the maximum life for the R5 curve with 45-year ASL is over 60 years; the oldest FPL plant is 49 years old as of December 31, 2009.

In our opinion, limited retirements lend credence to OPC's proposal for a longer life. However, we believe that 60 years is too long. Accordingly, we will use the R5 curve with a 52-year ASL.

With regard to net salvage, OPC argued that FPL's proposal "is based on its failure to properly analyze the data upon which it relied." OPC witness Pous primarily based his arguments on what he viewed as data manipulation, including the 2006 data. According to FPL witness Clarke, OPC witness Pous contended that reimbursed retirements should have been included. FPL witness Clarke contended that OPC's argument about discrepancies in 2006 data is related to hurricane-related retirements, which FPL removed from the data. As discussed above, we believe that FPL's approach with regard to reimbursed retirements and the effects of hurricanes is reasonable. Therefore, we approve a net salvage of (15) percent.

Account 355.00 – Poles and Fixtures

FPL proposed no change to the R2 curve, an increase in the ASL from 41 to 44 years, and no change to the (50) percent net salvage. OPC proposed that the net salvage be increased from the current (50) percent to (30) percent.

OPC witness Pous contended that FPL's "manipulation of its actual historical data is suspect." By this, OPC meant that FPL removed reimbursed retirements and hurricane related data. As discussed above, we believe that FPL's approach with regard to reimbursed retirements and the effects of hurricanes is reasonable.

OPC witness Pous also contended that FPL ignored more recent data with reduced negative net salvage. OPC argued that FPL did not consider economies of scale. OPC further argued that although FPL expected increased negative net salvage because of preservatives on the poles, FPL "admitted" that the majority of transmission poles are concrete. Witness Clarke responded to OPC's contention that FPL ignored recent data by explaining that "a more detailed look at the history of this account reveals that there is more of a cyclical trend . . . ." With regard to economies of scale, witness Clarke referred to an earlier discussion where he pointed out that for economies of scale to be pertinent, large numbers of retirements need to occur in close proximity.

We believe that FPL's removal of nonrecurring reimbursed retirements and hurricane data is appropriate; otherwise, this data might skew the results. After reviewing the data, we believe that the data is probably more cyclical in nature than not. While some economies of scale might be present, they are probably small once hurricane data is excluded. Accordingly, we find that (50) percent net salvage is appropriate.

Account 356.00 – Overhead Conductors and Devices

FPL proposed no change in the R1.5 curve, an increase in the ASL from 44 to 47 years, and a decrease in net salvage from (45) to (50) percent. OPC proposed an S0 curve, an increase in the ASL to 51 years, and an increase in net salvage from (45) to (40) percent.

OPC witness Pous contended that his curve fitting technique provides a "somewhat better overall fit" than FPL's technique. As discussed above, we believe FPL's curve fitting technique is appropriate. Therefore, we will use the R1.5 curve.

OPC witness Pous asserted that the process of upgrading lower voltage transmission lines to higher voltage lines "artificially shortened the overall life expectancy of the previously retired investment." Thus, according to witness Pous, a longer ASL is indicated. Witness Pous contended that another reason for an increased ASL is the "not in my backyard" or "NIMB" syndrome.

FPL witness Clarke discounted OPC's arguments by asserting that the "data for this account is excellent and fits the Iowa curve selection very nicely." We believe that FPL has made the more persuasive case in its proposal to increase the ASL from 44 to 47 years.

With regard to net salvage, OPC argued that FPL manipulated the database by removing reimbursed retirements. As discussed above, we are of the opinion that FPL's approach on reimbursed retirements and hurricane effects is reasonable. Therefore, we approve a net salvage of (50) percent.

Account 357.00 – Underground Conduit

FPL proposed a change in curve from S3 to R4, an increase in the ASL from 46 to 60 years, and no change to the net salvage of 0 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, actuarial data and industry data support an increase in the ASL and a change to a "higher mode" curve. We note that whether the S3 or R4 curve is used with the ASL of 60 years, the remaining life differs by less than one year. With "limited" data, witness Clarke asserted that a net salvage "close to 0 percent is appropriate since underground conduits are generally abandoned in place." We believe that the R4 curve, and 60-year ASL are appropriate. We approve a net salvage of 0 percent.

Account 358.00 – Underground Conductors and Devices

FPL proposed a change in curve from S3 to L3, an increase in the ASL from 35 to 60 years, and a decrease in net salvage from 0 to (10) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the actuarial analysis results in life indications of 50 to 60 years, with industry data ranging between 30 and 60 years. Witness Clarke asserted that, "[g]enerally, the cost of removing wire from underground conduit is expected to be greater than its salvage value, thus net salvage of 0 or less is reasonable." According to witness Clarke, industry data suggest net salvage between 0 and (20) percent. Witness Clarke asserted that, for FPL, salvage data is "sporadic" for some years.

Using an S3 curve or an L3 curve with a 60-year ASL results in almost the same remaining life (difference of less than one year). We believe that the change in curve is reasonable. With regard to net salvage, there has been no gross salvage since 2000, while cost of removal has experienced considerable variance (e.g., 37 percent in 2006 and 509 percent in 2005). Overall, net salvage appears to be decreasing; therefore, we find that the decrease in net salvage to (10) percent is reasonable.

Account 359.00 – Roads and Trails

FPL proposed no change to the current curve, no change in the 50-year ASL, and a decrease in net salvage from 0 to (10) percent. OPC proposed that the ASL be increased to 65 years.

According to FPL witness Clarke, there is "very little activity in this account." Witness Clarke concludes, based in part on industry data, that a range of 50 to 70 years "would be consistent with the industry range." Witness Clarke decreased the net salvage because "there is [sic] some removal costs preparing to restore to pristine condition." According to witness Clarke, the cost of removal rates are (41) percent for the 20-year band and (48) percent for the 5-year band.

OPC argued that investments in this account can and will last longer than the 50 years proposed by FPL. According to OPC witness Pous, "limited level of retirement activity . . . is indicative of longer life spans for such investments." OPC witness Pous also compared FPL witness Clarke's proposal in this docket with proposals he made in other states. FPL witness Clarke opined that there is "no justification" for extending the life; furthermore, he asserted that witness Pous provided "no valid justification" for his proposal. Witness Clarke disagreed with OPC witness Pous that what witness Clarke proposed in other states is relevant in this case.

We agree with OPC that limited retirement activity lends support to an increase in life. Accordingly, we believe that a 65-year ASL for this account is reasonable.

2. Account-Specific Analysis: Distribution Plant

Account 361.00 – Structures and Improvements

FPL proposed a change in curve from L3 to R3, an increase in the ASL from 45 to 60 years, and no change to the net salvage of (15) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the actuarial analysis supports a change in curve and an increase in life. Industry lives for this account range from 30 to 65 years. Changing the curve from L3 to R3 with a 60-year ASL results in remaining lives that are less than one year apart. According to witness Clarke, cost of removal is increasing, but gross salvage is "negligible." We believe that the R3 curve, and 60-year ASL are appropriate. We approve a net salvage of (15) percent.

Account 362.00 – Station Equipment

FPL proposed no change in the R1.5 curve, an increase in the ASL from 38 to 41 years, and no change in the (10) percent net salvage. OPC proposed a change in the curve from R1.5 to S0 and an increase in the ASL from 38 to 48 years.

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OPC argued that its curve fitting technique, which places greater emphasis on the level of exposures, is appropriate. As discussed above, we believe that FPL's technique is appropriate; therefore, we will use the R1.5 curve. OPC witness Pous also contended that FPL's industry average is 46 years. FPL witness Clarke disagreed with OPC's proposed increase in the ASL to 48 years. However, we believe that a modest increase in life beyond FPL's is warranted. Therefore, we increase the life to 43 years.

Account 364.00 – Poles, Towers, and Fixtures

FPL proposed a slight change in the curve, from R1.5 to R2, an increase in the ASL from 34 to 37 years, and a decrease in net salvage from (40) percent to (125) percent. OPC proposed the curve remain at R1.5, an increase in the ASL from 34 to 41 years, and a decrease in net salvage from (40) percent to (60) percent.

OPC witness Pous contended that his proposed curve and ASL are a "superior fit" compared to FPL's proposal. Witness Pous asserted that FPL's statements that "most poles in the system are concrete poles is incorrect;" the "vast majority" of poles are wood poles. According to witness Pous, FPL recognized, but did not appear to incorporate, programs to extend the life of wood poles. Witness Pous averred that industry data supports an ASL longer than the 37 years proposed by FPL. FPL witness Clarke asserted that FPL is "not sure" how many wood poles will be replaced with concrete poles. Witness Clarke contended that his ASL proposal extends the life, but to increase it even more "is not justified at this time." Additionally, according to witness Clarke, using the average life in the industry is "incorrect." We believe it is reasonable to extend the ASL further; however, we believe that a compromise ASL of 39 years is appropriate based on the record. We also believe that the R2 curve is appropriate.

FPL proposed to decrease net salvage from (40) to (125) percent because of a "large increase in removal costs." OPC proposed a much smaller decrease in net salvage from (40) to (60) percent. OPC argued that FPL's proposal is the "most aggressive depreciation practice presented by the Company." OPC witness Pous contended that a review of the data indicates FPL "has significantly manipulated the historical results" by removing reimbursed retirements. Witness Pous also asserted that while FPL "has raised concerns" about the disposal of treated wood poles, FPL "fails to note" the level of investment of concrete poles (18 percent), and that FPL is adding concrete poles at a faster rate than wood poles.

As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. A review of the data shows that cost of removal is increasing and gross salvage is decreasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why this is occurring and whether it is possible for FPL to make internal changes that might mitigate this trend. We are of the opinion that FPL's proposed decrease in net salvage is too large and may well be premature. OPC's proposed net salvage of (60) percent represents a moderate decrease in net salvage, yet it still reflects FPL's actual experience. Accordingly, we approve (60) percent net salvage.

Account 365.00 – Overhead Conductors and Devices

FPL proposed a slight change in curve, from S0.5 to S0, an increase in the ASL from 35 to 40 years, and a decrease in net salvage from (50) to (100) percent. OPC proposed the S0 curve, an increase in the ASL to 43 years, and no change in net salvage of (50) percent.

OPC argued that its proposed 43-year ASL is the "only credible recommendation in the record." OPC witness Pous contended that if FPL had used the 20-year experience band, the ASL "would have to be increased" to 46 years instead of 40 years. Additionally, according to witness Pous, industry information would support an ASL in the "mid 40s." FPL witness Clarke contended that his statistical analysis was "good" and his proposal was a "good fit both graphically and mathematically." Witness Clarke asserted that witness Pous did not explain why a 20-year band should be used. Since both parties made good arguments, a compromise on the ASL is reasonable. Therefore, we will use an S0 curve and 41-year life.

FPL proposed a net salvage of (100) percent, in effect doubling the negative net salvage. OPC witness Pous contended that FPL's proposal was made "without adequate or reasonable justification for its position." According to witness Pous, FPL did not investigate a "significant anomaly," a large negative gross salvage in 2006. FPL responded that it considered the amount an outlier. FPL witness Clarke contended that assuming an "average" salvage in 2006, the net salvage would have been over (90) percent. According to OPC witness Pous, the "disproportionate retirement level of switches in the historical database is skewing" FPL's proposal. FPL witness Clarke responded that he looked at all retirements, not just the 10 percent of retirements comprised of switches. Part of OPC's argument refers to reimbursed retirements.

As discussed above, we believe that FPL's approach to reimbursed retirements is reasonable. However, such a large decrease in net salvage is without adequate support. A review of the data shows that cost of removal is increasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why the cost of removal is increasing and whether it is possible for FPL to make internal changes that might mitigate this trend. A modest decrease in net salvage, reflecting the data, is appropriate. Accordingly, we approve (60) percent net salvage.

Account 366.60 – Underground Conduit, Duct System

FPL proposed a small change in the curve, from S3 to S1.5, an increase in the ASL from 48 to 70 years, and an increase in the net salvage from (10) percent to (5) percent. OPC proposed a net salvage of 0 percent.

OPC argued that FPL's proposed increase in net salvage is "inadequate." OPC witness Pous asserted that the 5-year salvage band results support a 0 percent net salvage; however, the 3-year bands are positive. According to witness Pous, "[I]f reimbursed retirements are recognized, the historical database turns *positive* overall." As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. However, after an evaluation of the data, the record supports an increase in the net salvage somewhat more than FPL's proposal. We find that a net salvage of (2) percent is appropriate.

Account 366.70 – Underground Conduit, Direct Buried

FPL proposed a change in curve from S3 to R4, an increase in the ASL from 41 to 50 years, and no change in the 0 percent net salvage. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the results of the actuarial analysis were "poor." Lives in the industry range from 35-80 years. Witness Clarke asserted that the S3 curve is "too short" and the ASL should be increased. According to witness Clarke, the "cost of removal and [gross] salvage percents are all over the place for this account;" therefore, his proposal is to retain the net salvage. We will use the R4 curve, and 50-year ASL. We approve a net salvage of 0 percent.

Account 367.60 – Underground Conductors and Devices Duct System

FPL proposed to retain the S0 curve, 38-year ASL, and (5) percent net salvage. OPC proposed a curve change from S0 to L1, an increase in the ASL from 38 to 40 years, and an increase in net salvage from (5) percent to 0 percent.

OPC argued that the L1 curve is a better fit through the first 12 to 13 years. As discussed above, we believe that FPL's curve fitting technique is appropriate. Therefore, we will use the S0 curve. OPC witness Pous contended that tree retardant cable, which comprises over 22 percent of the investment, provides support for a longer ASL. FPL witness Clarke responded that he was unaware that there was an established industry life for tree retardant cable longer than 38 years. We believe FPL's argument persuasive; therefore, we will use an S0 curve and 38-year ASL.

For net salvage, OPC based its proposal, in part, on reimbursed retirements. As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. We find that 0 percent net salvage is appropriate based on the data.

Account 367.70 – Underground Conductors Devices Direct Buried

FPL proposed a change in curve from R2.5 to R2, an increase in the ASL from 34 to 35, and no change in the 0 percent net salvage. OPC proposed a change in curve from R2.5 to S0.5 and an increase in the ASL from 34 to 43 years.

OPC argued that its "presentation of a better curve fit was unrebutted." OPC witness Pous asserted that his proposed curve is a better fit than FPL's during different periods. As discussed earlier, we believe that FPL's curve fitting technique is appropriate; therefore, we approve the R2 curve. OPC witness Pous contended that the slowing of retirements in the last six years would support an increased ASL beyond FPL's proposal. According to FPL witness Clarke, while retirements had slowed down, they have begun to increase again. We believe that a 35-year ASL is reasonable and supported by the evidence.

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Account 368.00 – Line Transformers

FPL proposed a change in curve from L2 to L1.5, an increase in the ASL from 31 to 32, and an increase in net salvage from (35) percent to (25) percent. OPC proposed the L1.5 curve, an ASL of 34 years, and an increase in net salvage to (20) percent.

OPC argued that its proposed curve is a better fit for ages less than 24.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the L1.5 curve. OPC witness Pous asserted that his ASL recommendation of 34 years is closer to the industry average ASL than FPL's. Although FPL witness Clarke mentioned OPC's discussion of industry averages, witness Clarke did not refute the use of averages; rather, he contended that the statistical analysis was "good" and that his proposed curve and life "fit good both graphically and mathematically." According to witness Clarke, the industry range is 26-45 years. We believe that an increase in the ASL to 33 years is reasonable and appropriate.

FPL witness Clarke asserted that his proposed increase in net salvage is based on a decline in the cost of removal with almost no gross salvage. OPC argued that FPL's proposal is insufficient. Witness Clarke contended that OPC has "no facts" for increasing the net salvage compared to what FPL proposed. After reviewing the data, we find that an increase in net salvage from (35) to (25) percent is reasonable.

Account 369.10 – Services, Overhead

FPL proposed a small change in the curve, from R1.5 to R1, an increase in the average service life, from 36 to 48 years, and a decrease in the net salvage, from (60) percent to (125) percent. OPC proposed that the net salvage be decreased from (60) percent to (85) percent.

OPC provided several arguments against decreasing the net salvage. First, OPC witness Pous asserted that FPL's current net salvage is "already more negative than the industry average by a significant level." Second, witness Pous contended that FPL's accounting practices are "suspect." Third, according to witness Pous, FPL's proposed net salvage would produce $4.2 million of negative net salvage, an amount that is "almost *four* times the average level of negative net salvage the Company has experienced throughout its historical database . . . ." Additionally, OPC argued that FPL's proposal was made "without any consideration of what causes it to be so much more negative than the industry."

According to FPL witness Clarke, net salvage has been more than (200) percent in some recent years. Witness Clarke asserted that a "direct comparison of FPL to the companies in my industry group would not be an 'apples to apples' comparison." This is because of the "many factors" that influence FPL's data, including "accounting policies, Operation and Maintenance (O&M) practices, management policies, etc."

It is clear from a review of the data that cost of removal is increasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why the cost of removal is increasing and whether it is possible for FPL to make internal changes that might mitigate this trend. We are also of the opinion that decreasing net salvage from (60) to (125) percent is far too

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drastic. Accordingly, we approve decreasing net salvage from (60) to (85) percent because this is a moderate change that, nonetheless, recognizes what is occurring in this account.

Account 369.70 – Services, Underground

FPL proposed no change in the R2 curve, 34-year ASL, and (10) percent net salvage. OPC proposed a change in curve from R2 to S0.5, an increase in the ASL from 34 to 41 years, and an increase in net salvage from (10) percent to (5) percent.

OPC witness Pous contended that its proposed curve is an "excellent" fit through the first 13.5 years of age. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2 curve. According to witness Pous, FPL did not state that the average ASL for its industry database is 39 years, five years longer than FPL's proposed ASL, while OPC's proposal is two years higher. According to FPL witness Clarke, retirements in this account are "very small compared to the exposures." We believe that an ASL of 38 is both moderate and reasonable, taking into account what appears to be longer living plant.

OPC argued that the "only credible evidence in the record supports" OPC's net salvage proposal. Witness Pous averred that there appears to be a correlation between quantity retired and cost of removal, such that economies of scale had an impact. FPL witness Clarke alleged that witness Pous "attempts to confuse the record." We disagree. We find that an increase in net salvage to (5) is appropriate based on data and the record.

Account 370.00 – Meters

FPL proposed a change in curve from S2 to R2.5, an increase in the ASL from 34 to 36 years, and a decrease in net salvage from (30) percent to (55) percent. OPC proposed a curve of S1.5, an ASL of 38, and net salvage of (10) percent.

According to OPC witness Pous, his visual curve fitting technique produces a better fit through the first 22.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2.5 curve. OPC argued that based on actuarial analysis, an ASL of 38 years is warranted. FPL expects to retire approximately 4.3 million meters in the next five years, to be replaced with AMI meters (Account 370.10). We believe that increasing the ASL beyond 36 years is premature because of the planned replacements of meters.

OPC argued that FPL did not establish that its historical net salvage "is indicative of what will transpire in the future . . . ." OPC witness Pous asserted that FPL did not refer to industry data when discussing this account because if it had, "it would have become patently clear that the Company's proposal falls so far outside reasonable bounds as to lack credibility." According to OPC witness Pous, the industry database upon which FPL relied shows an average net salvage of (3) percent, with the most negative net salvage at (25) percent. OPC witness Pous based his recommendation on a cost of removal estimate of $5.63 per meter, taken from a case in Texas. Witness Pous applied $5.63 to FPL's 4.3 million meters that will be retired in the next five years, yielding an approximate net salvage of (10) percent. FPL witness Clarke contended that retiring 4.3 million meters will have "no bearing" on the contents of this account. Witness Clarke

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asserted that his proposed net salvage relates to those meters not being replaced with AMI meters because meters removed due to the AMI program will be moved to a capital recovery schedule.

We are troubled by such a high proposed cost of removal. Although the data may appear to support a higher cost of removal, FPL did not provide an analysis of why the cost of removal is high. Accordingly, we believe it would be a useful exercise for FPL to investigate and determine the reasons for the high cost of removal in this account. We believe it is premature to increase the cost of removal. At the same time, the data indicates a net salvage less than OPC's proposal. Therefore, we approve a net salvage of (30) percent.

Account 370.10 – Meters – AMI

This is a new subaccount, containing AMI meters. FPL proposed a curve of R2.5, an ASL of 20 years, and (55) percent net salvage. OPC proposed a net salvage of (10) percent.

FPL based its curve on the curve for Account 370.00, Meters, and its proposed ASL on the manufacturer's suggested 20-year life. We believe that this is reasonable.

With regard to net salvage, FPL witness Clarke noted that AMI meters are "new and no historical information is available." FPL witness Clarke asserted that there is no reason to use a different net salvage for this account than for Account 370.00, Meters. Therefore, he recommended the same net salvage percent that he recommended for Account 370.00, Meters. OPC argued that its recommendation also relies on its recommendation for Account 370.00, Meters.

At this time, we agree that the net salvage for this account should be the same as the net salvage for Account 370.00, Meters. Therefore, based on the discussion in Account 370.00, Meters, we find that a net salvage of (30) percent is appropriate.

Account 371.00 – Installations on Customer's Premises

FPL proposed a slight curve change, from L1 to L0, an increase in the ASL from 15 to 30 years, and a decrease in net salvage from (15) to (25) percent. None of the intervenors offered any proposal for this account.

Most additions to this account occurred within the last 30 years. Industry lives range from 10 to 30 years, averaging 22 years. According to FPL witness Clarke, the current L1 curve and 15-year life are "low for this type of equipment and within the industry range." We believe that the L0 curve and 30-year ASL are reasonable.

Witness Clarke asserted that the cost of removal increased in the last five to six years, while gross salvage has decreased. According to witness Clarke, the industry range is from 0 to (40) percent. Witness Clarke's proposed decrease in net salvage derives from the last five years. We believe a decrease in net salvage is reasonable; however, a change from (15) to (25) percent is too drastic based on the evidence. We believe that a more moderate change is appropriate. Accordingly, we find that a net salvage of (20) percent is appropriate.

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Account 373.00 – Street Lighting and Signal Systems

FPL proposed a change in curve from S-0.5 to R0.5, an increase in the ASL from 20 to 30 years, and an increase in net salvage from (35) to (20) percent. OPC proposed an L0 curve with a 35-year life.

OPC witness Pous asserted that his curve fitting technique is a better fit through the first 10.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R0.5 curve.

OPC argued that FPL "failed to consider the technological changes" that have occurred to this account's investment. OPC witness Pous asserted that the changes in technology in this account have led to shorter ASLs (for existing plant). Therefore, according to witness Pous, OPC's recommended 35-year life is a "conservative estimate at this point in time," because FPL has not identified any new technologies. According to FPL witness Clarke, FPL did not identify any changes in the near future; therefore, witness Clarke asserted that he did not believe that OPC had a "valid basis" for its prediction. We do not believe the record supports an increase in the ASL from 20 to 35 years. Therefore, we believe that a 30-year ASL is appropriate.

Account 390.00 – Structures and Improvements

FPL proposed a change in curve from S1 to R1.5, an increase in the ASL from 38 to 50 years, and a decrease in net salvage, from 0 percent to (10) percent. OPC proposed an L0 curve, an increase in the ASL to 56 years, and an increase in net salvage from 0 to 25 percent.

OPC witness Pous contended that his curve is a better fit through the first 10.5 years of life. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R1.5 curve.

OPC argued that its proposal to increase the ASL to 56 years is "conservative." According to OPC witness Pous, FPL "understates the realistic and reasonable ASL for this account." Witness Pous contended that because this account contains ten buildings comprising approximately 64 percent of the investment, an ASL longer than FPL's proposed ASL is "well warranted." OPC witness Clarke asserted that the ten buildings "also include ancillary components such as roofs, air conditioning, lighting systems, etc." We agree that the ASL should be increased and we believe that an increase to 50 years is moderate and supportable.

With regard to net salvage, OPC argued that over 40 percent of the investment is in FPL's two largest office complexes, and that the trend in commercial real estate is capital appreciation, not depreciation. OPC witness Pous asserted that the negative net salvage derives from retirements of building components, such as roofs. FPL witness Clarke asserted that assets such as roofs are what FPL expects to retire in the future. Witness Clarke contended that "substantial appreciation" in real estate has not occurred in Florida since 2005. Witness Clarke also asserted that if FPL were to retire any of these buildings, they would "probably be worthless as-is, without improvements." Only the land would have value, according to witness Clarke; however, the land is owned by shareholders who do not receive return of their capital through

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rates. We believe that FPL makes a more persuasive case; however, FPL's view of the net salvage for this account is unnecessarily bleak. Accordingly, we approve a net salvage of (5) percent.

Account 392.10 – Transportation – Automobiles

FPL proposed a small change in the curve, from L3 to L2, a decrease in average service life from eight to six years, and an increase in net salvage from 10 to 15 percent. None of the intervenors offered a proposal for this account.

According to FPL witness Clarke, FPL personnel "mentioned the lives of automobiles were getting shorter in recent years," and Company records confirmed that, showing "automobiles were sold after 6 years." Also, according to witness Clarke, the cost of removal is 0 while salvage is "around 15 percent," representing an increase in salvage. We believe that the L2 curve, and six-year ASL are appropriate, and we find that a 15 percent net salvage is reasonable.

Account 392.20 – Transportation – Light Trucks

FPL proposed a change in curve from S3 to L3, no change in the nine-year ASL, and no change to the 15 percent net salvage. None of the intervenors offered a proposal for this account.

FPL witness Clarke's actuarial analysis resulted in lives of around eight and one half to nine years. FPL personnel confirmed that eight to nine years is the life for light trucks. According to witness Clarke, the curve "should be changed to reflect the life analysis results." Witness Clarke asserted that although the gross salvage showed a "slight increase," the net salvage (cost of removal is 0) should remain at 15 percent because the increase may result from "one year of suspect data."

After reviewing the salvage data, we agree that the indicated increase in salvage may be the result of bad data. Even if the increase is not because of bad data, it is premature to increase the net salvage. Therefore, we believe that the L3 curve, and nine-year ASL are appropriate, and we find that a 15 percent net salvage is reasonable.

Account 392.30 – Transportation – Heavy Trucks

FPL proposed no change in the S3 curve, an increase in the ASL from 11 to 12 years, and an increase in net salvage from 10 percent to 15 percent. None of the intervenors offered a proposal for this account.

FPL witness Clarke based his increased life proposal on both actuarial analysis and information from FPL personnel. According to witness Clarke, a salvage analysis showed increasing salvage and no cost of removal. We believe that it is reasonable to retain the S3 curve, and to increase the ASL to 12 years, and we find that it is appropriate to increase the net salvage to 15 percent.

Account 392.40 – Transportation – Tractor Trailers

FPL proposed a change in curve from S2 to L2.5, a decrease in the ASL from 11 to nine years, and a decrease in net salvage from 15 to 0 percent. None of the intervenors offered a proposal for this account.

According to witness Clarke, actuarial analysis showed a nine-year life, which was confirmed by FPL personnel. Witness Clarke asserted that an L2.5 curve and a nine-year life "better reflect [the] life analyses." No cost of removal or gross salvage has been recorded for this account since 2000; therefore, witness Clarke recommended a net salvage of 0 percent.

We believe that the L2.5 curve and a nine-year ASL are reasonable. We find that decreasing the net salvage from 15 to 0 percent is appropriate since there has not been any cost of removal or gross salvage recorded since 2000.

Account 392.90 – Transportation – Trailers

FPL proposed a small change in the curve, from L2 to L1, an increase in the average service life from 18 to 20 years, and a decrease in net salvage from 30 to 15 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, FPL personnel informed him that these trailers last between 15 to 25 years. The actuarial analysis showed lives of about 20 years, with a low order curve. We believe that an L1 curve and ASL of 20 years are reasonable.

Witness Clarke's net salvage proposal stems from an analysis that showed "very little salvage and no removal costs being recorded in the past few years." Witness Clarke averred that the "estimate of 30 percent net salvage is too high and should be decreased." We note that gross salvage has varied widely since 2001. We believe it is premature to reduce the net salvage; therefore, we approve a 30 percent net salvage.

Account 396.10 – Power Operated Equipment – Transportation

FPL proposed a small change in curve, from L0 to L0.5, an increase in the ASL from nine to 10 years, and no change in the 20 percent net salvage. None of the intervenors offered any proposal for this account.

FPL witness Clarke proposed the increase in the ASL based on the actuarial analysis and information from FPL personnel. Witness Clarke testified that there is no cost of removal; however, gross salvage data "does not look good for [the] last five years." Prior to the last five years, gross salvage averaged around 20 percent. Witness Clarke's proposal is to retain the current 20 percent net salvage. We agree that the salvage data is problematic; thus, we find that retaining 20 percent net salvage is reasonable. We also believe that the L0.5 curve and 10-year ASL are reasonable.

Account 396.80 – Other Power Operated Equipment

FPL proposed a change in curve from S1 to L0.5, no change in the nine-year ASL, and no change in the 20 percent net salvage. None of the intervenors offered any proposal for this account.

Witness Clarke proposed the curve change based on his actuarial analysis. According to witness Clarke, no cost of removal or salvage data has been recorded since 2000. Witness Clarke proposed that this account use the same net salvage as Account 396.1, Power Operated Equipment, i.e., 20 percent, "[u]ntil the data is reviewed." The current net salvage for this account is 20 percent. We believe that the L0.5 curve, and nine-year ASL are reasonable. We find that a 20 percent net salvage is reasonable.

Account 397.80 – Communications Equipment – Fiber Optics

FPL proposed no change in the L0 curve, no change in the 10-year ASL, and a decrease in net salvage from five to 0 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, there was "insufficient data to perform an actuarial life analysis." Witness Clarke noted that the fiber optic equipment in this account was "spun off" in 2000; the remaining investment is the electronics equipment. Therefore, witness Clarke recommended no change in the curve or average service life. Witness Clarke asserted that the data for the salvage analysis is "erratic and missing many years." He recommended ignoring the salvage data and using 0 percent net salvage "until data is revised."

After reviewing the cost of removal and salvage data, we agree with witness Clarke that the data should be ignored. We agree with FPL's proposal; therefore, the net salvage shall be reduced to 0 for this account. We believe that it is reasonable to retain the L0 curve and 10-year ASL.

3. Amortizations

General Accounts

Pursuant to Rule 25-6.04361(5)(f), F.A.C., certain General Plant Accounts may use an amortization schedule. FPL proposed to amortize these accounts in accordance with the rule. Under FPL's proposal, there will be no change to the depreciation accrual. None of the intervenors offered a proposal for these accounts. The approved amortizations are shown in Table 4:

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Table 4: General Account Amortizations

Account No.	Account Name	Amortization Period (Years)
391.10	Office Furniture	7.0
391.20	Office Accessories	5.0
391.30	Office Equipment	7.0
391.40	Duplicating & Mailing Equipment	7.0
391.50	EDP Equipment	5.0
391.70	PC Equipment (ECCR)	3.0
391.90	Personal Computer Equipment	3.0
392.70	Transportation Equipment – Marine	5.0
393.10	Stores Equipment – Handling Equipment	7.0
393.20	Stores Equipment – Storage Equipment	7.0
394.20	Shop Equipment – Portable Handling	7.0
395.20	Lab Equipment – Portable	7.0
395.60	Laboratory Testing Equipment (LMS)	5.0
397.20	Communications Equipment – Other 7-Yr Amrt	7.0
397.30	Communications Equipment – Official	7.0
397.40	Communication Equipment (ECCR)	5.0
398.00	Miscellaneous Equipment	7.0

Other Accounts

Pursuant to Order No. PSC-05-0902-S-EI, issued on September 14, 2005, in Docket No. 050188-EI, four other amortizations were permitted. The other amortizations are contained in Table 5:

Table 5: Amortizations for Other Accounts

Account No.	Account Name	Amortization Period (Years)
362.90	Substation Equipment – LMS	5.0
367.50	UG Conduct & Dev., Cable Injection–20+ Years	29.0(*)
367.90	UG Conduct & Dev., Cable Injection–10 Years	10.0
371.20	Residential Load Management	5.0

*Per Order No. PSC-94-1199-FOF-EI, issued on September 30, 1994, in Docket No. 931231-EI, the 20-year guaranteed cable injection is to be recovered over the remaining life of the cable. The remaining life shown is the approved remaining life.

In this proceeding, FPL proposed to continue using the previously-approved amortizations. None of the intervenors offered any proposal for these accounts. The only change to the depreciation accrual will be for Account 367.50, which, by our prior order, is tied to the remaining life of the cable. Therefore, we approve the amortizations contained in Tables 4 and 5.

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In conclusion, we approve the remaining life, net salvage percent, allocated reserve percent, amortizations, and resulting rates for each transmission, distribution, and general plant account contained in Table 6, on the following pages.

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Table 6: Transmission, Distribution, and General Plant Depreciation Components and Resulting Rates

Account Number and Description	COMMISSION APPROVED Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
TRANSMISSION PLANT				
350.2 Easements	58	0.00	22.67	1.3
352.0 Structures & Improvements	47	(15.00)	24.92	1.9
353.0 Station Equipment	29	(2.00)	28.05	2.6
353.1 Station Equipment - Step-Up	25	0.00	28.57	2.9
354.0 Towers & Fixtures	34	(15.00)	39.81	2.2
355.0 Poles & Fixtures	33	(50.00)	37.50	3.4
356.0 OH Conductors & Devices	35	(50.00)	38.30	3.2
357.0 Underground Conduit	40	0.00	33.33	1.7
358.0 Undg. Conductors & Devices	40	(10.00)	36.67	1.8
359.0 Roads & Trails	47	(10.00)	30.46	1.7
DISTRIBUTION PLANT - DEPRECIABLE				
361.0 Structures & Improvements	50	(15.00)	19.17	1.9
362.0 Station Equipment	33	(10.00)	25.58	2.6
364.0 Poles, Towers & Fixtures	27	(60.00)	49.23	4.1
365.0 Overhead Conductors & Devices	30	(60.00)	42.93	3.9
366.6 Undg. Conduit, Duct	59	(2.00)	16.03	1.5
366.7 Undg.Conduit, Direct Buried	40	0.00	20.00	2.0
367.6 Undg. Conductors & Devices, Duct	29	0.00	23.68	2.6
367.7 Undg. Conductors & Devices, Buried	18.4	0.00	47.43	2.9
368.0 Line Transformers	22	(25.00)	41.67	3.8
369.1 Services, Overhead	36	(85.00)	46.25	3.9
369.7 Services, Underground	26	(5.00)	33.16	2.8
370.0 Meters	24	(30.00)	43.33	3.6
370.1 AMR Meters	19.2	(30.00)	5.20	6.5
371.0 Installations on Customer's Premises	22	(20.00)	32.00	4.0
373.0 Street Lighting & Signal Systems	22	(20.00)	32.00	4.0
GENERAL PLANT - DEPRECIABLE				
390.0 Structures & Improvements	36	(5.00)	29.40	2.1
392.1 Transportation - Automobiles	3	15.00	42.50	14.2
392.2 Transportation - Light Trucks	4.6	15.00	41.56	9.4
392.3 Transportation - Heavy Trucks	5	15.00	49.58	7.1
392.4 Transportation - Tractor-Trailers	2.6	0.00	71.11	11.1
392.9 Transportation - Trailers	11.9	30.00	28.35	3.5
396.1 Power Operated Equipment (Transp.)	6.3	20.00	29.60	8.0
396.8 Other Power Operated Equipment	5.2	20.00	33.78	8.9
397.8 Commun. Equipment - Fiber Optics	7.7	0.00	23.00	10.0

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Table 6: Amortization Items

Account Number and Description	COMMISSION APPROVED			
	Average Remaining Life	Net Salvage	Theoretical Reserve	Remaining Life Rate
	(yrs.)	(%)	(%)	(%)
DISTRIBUTION - AMORTIZABLE				
362.9 Substation Equipment - LMS	5 Year Amortization			
367.5 UG Cable Injection - 20+ Year	29 Year Amortization			
367.9 UG Cable Injection - 10 year	10 Year Amortization			
371.2 Residential Load Management	5 Year Amortization			
GENERAL PLANT - AMORTIZABLE				
391.1 Office Furniture	7 Year Amortization			
391.2 Office Accessories	5 Year Amortization			
391.3 Office Equipment	7 Year Amortization			
391.4 Duplicating & Mailing Equipment	7 Year Amortization			
391.5 EDP Equipment	5 Year Amortization			
391.7 PC Equipment (ECCR)	3 Year Amortization			
391.9 Personal Computer Equipment	3 Year Amortization			
392.7 Transportation Equip. - Marine	5 Year Amortization			
393.1 Stores Equip. - Handling Equip.	7 Year Amortization			
393.2 Stores Equip. - Storage Equipment	7 Year Amortization			
394.2 Shop Equip. - Portable Handling	7 Year Amortization			
395.2 Lab Equipment - Portable	7 Year Amortization			
395.6 Lab. Testing Equip. (LMS)	5 Year Amortization			
397.2 Comm. Equip. - Other 7-Yr Amort	7 Year Amortization			
397.3 Comm. Equipment - Official	7 Year Amortization			
397.4 Communication Equip. (ECCR)	5 Year Amortization			
398.0 Miscellaneous Equipment	7 Year Amortization			

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Reserve Imbalance

The theoretical reserve is the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. The difference between the theoretical reserve and the book reserve is a reserve imbalance. If the calculated theoretical reserve is more than the book reserve, the imbalance is a reserve deficit. If the calculated theoretical reserve is less than the book reserve, the imbalance is a reserve surplus.

Applying its proposed depreciation life and salvage parameters, FPL calculated a reserve surplus of $1.245 billion. OPC calculated a reserve surplus of $2.75 billion based on its proposed depreciation formula. The formula for the prospective theoretical reserve is provided in Rule 25-6.0436(4)(k), F.A.C. Using this formula and the life and salvage components approved above, we calculate a reserve surplus of $1,208.8 million, as shown in Table 7 below:

Table 7: Reserve Imbalance	
	($000,000)
Steam Production	353.1
Nuclear Production	127.0
Other Production	119.6
Transmission	12.1
Distribution	555.6
General	41.4
Total Reserve Imbalance	1,208.8

Corrective reserve measures

Having determined above that there is a theoretical reserve surplus, the parties asked us to determine what, if any, corrective measures should be taken. The crux of the parties' dispute was whether the reserve imbalance should be corrected over the remaining life of the assets or over a shorter period of time. FPL argued that the surplus should be addressed through the remaining life rate design of its plant (22 years), rather than "accelerating" the recovery over a short period of time as suggested by the intervenors. FPL contended that the remaining life approach to resolve reserve imbalances is the norm and there is no reason to deviate. OPC, FIPUG, and FRF asserted that the magnitude of the reserve imbalance warranted a corrective approach shorter than the normal remaining life depreciation approach. SFHHA did not address the magnitude of the surplus, but asserted that it should be amortized over a short period of time.

FPL argued that a short amortization of the reserve surplus would have "the direct and unavoidable effect of rapidly increasing rate base, the required return on rate base, and future depreciation expense – all of which will have to be borne by future customers." FPL suggested that a middle path would be to transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. FPL argued that this action could provide "a measure of shorter-term relief for customers without doing as much damage to regulatory practices and future customers' pocketbooks." AIF supported FPL's position.

While OPC witness Pous calculated a reserve surplus of $2.75 billion using his proposed life and salvage values, he recommended that only FPL's identified reserve surplus of $1.25 billion be amortized over four years. OPC and FIPUG proposed that $314.3 million of FPL's reserve surplus should be first applied to offset the unrecovered costs associated with FPL's proposed capital recovery schedules for near-term retirements. OPC asserted that a four year amortization of the remaining balance of $894.6 million would reduce test year depreciation expense, thereby lowering FPL's revenue requirements. OPC submitted that amortizing the reserve surplus represented the most appropriate remedy to eliminate the intergenerational inequity the surplus created. FRF supported the OPC position that $1.25 billion of the reserve surplus be amortized over four years. SFHHA suggested that we require FPL to amortize its calculated reserve surplus of $1.245 billion over a five-year period. SFHHA asserted that the calculated surplus demonstrated that FPL's past depreciation rates were excessive, considering present expectations regarding depreciation parameters.

FIPUG witness Pollock proposed a slightly different approach to correct the remaining $894.6 million surplus. The witness proposed that FPL continue to record the $125 million annual credit to depreciation expense until the next depreciation study review.

Amortization of the reserve surplus will serve to decrease the reserve over the amortization period, thus increasing rate base. At the time of FPL's next depreciation review, its reserve positions will be lower, thereby resulting in higher depreciation rates, all other things remaining equal. Indeed, OPC recognized that depreciation rates in the instant proceeding are higher due to the lower reserve position resulting from the $500 million depreciation credit the Company recorded during the years 2005-2009, in accord with the 2005 Settlement Order. However, as noted by witness Pous, FPL's calculated theoretical reserve is lower by $500 million.

OPC argued that a reserve imbalance violated the matching principle.[25] The intervenors claimed that the existence of FPL's reserve imbalance indicates that past and current customers have paid more than their fair share of depreciation expenses and that future customers will therefore pay less than their fair share. In contrast, FPL contended that intergenerational inequity concerns are mitigated by the fact that customer rates were not increased during the time when the reserve surplus accumulated.

OPC contended that whether the remaining life methodology was adequate to address reserve imbalances depended on the magnitude of the imbalance and the time frame over which it would be corrected. The relative adequacy of the reserve causes the remaining life rate formula to self-adjust for historic over- or under-recovery, as well as for changes in projected life or salvage parameters. A reserve imbalance indicates a failure of the matching principle. The

[25] The matching of the period of time over which depreciation expense is collected with the service life of the group of assets is called the matching principle. Customers benefitting from the assets should be those who pay for the assets.

depreciation expenses of the past were misstated, so correction should be made now to reduce the misstatement into the future. Correction of the imbalance will result in a return to the matching principle. In this case, OPC argued that FPL's reserve imbalance was so great that recovery over the remaining life (22 years) was inadequate.

We believe that the very presence of a reserve imbalance indicates the existence of intergenerational inequity. Based on what is known today, the life estimates of yesterday are now viewed as being too short. FPL has lengthened the life span estimates for its production plants. Net salvage estimates have changed. This does not mean however, that past life and salvage estimates were wrong. Disregarding the fact that settlements were reached in 2002[26] and 2005[27] that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of FPL's depreciation parameters was in Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.

We agree with FPL witness Deason and OPC witness Pous that it is unlikely there would ever be a time when there is no reserve imbalance, simply because as time passes, more information is known and better estimates of life and salvage can be determined. However, that is not a reason to defer taking some action to correct reserve imbalances, where possible, either through reserve transfers or an amortization. The magnitude of the reserve imbalance should also dictate what action is taken. The matching principle argues for a quick correction of any surplus; the quicker the better so that the ratepayers who may have overpaid would have a chance of benefitting.

We agree with FPL that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase, thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase.[28] At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that under present expectations more than enough has been recovered, so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future.

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[26] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

[27] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[28] About $300 million of FPL's current base rate increase is due to the $125 million annual depreciation expense credit that was recorded in accord with the 2005 FPL Rate Case Settlement Order.

The remaining life rate typically carries the burden of correcting any reserve imbalance. A significant reserve imbalance can distort resulting depreciation rates. For example, an account with a 40-year average service life, 20-year average remaining life, zero percent net salvage, and 80 percent reserve would result in an average remaining life rate of 1.0 percent. This is due to the fact that the reserve should theoretically be 50 percent rather than 80 percent. The surplus in the reserve results in a remaining life depreciation rate being lower than it otherwise would be to correct the surplus over the remaining life. If the account reserve is restated to its theoretically correct level, the resulting depreciation rate is 2.5 percent. Thus, the presence of the reserve surplus depresses the resulting depreciation rate from 2.5 percent to 1.0 percent. The more significant the reserve surplus, the more depressed the resulting remaining life rate will be.

The intervenors contended that our past orders support a position that reserve imbalances have historically been recovered over a period of time that is shorter than the average remaining life. FPL, on the other hand, contended that the orders referenced by the intervenors are not applicable to FPL's circumstances. FPL witness Davis also asserted that none of the actions in the referenced orders had any impact on customer rates.

In the 1990s, we allowed FPL to record additional depreciation expense to reduce the potential for stranded investments. In 1995, we authorized FPL to record $126 million in additional depreciation expenses to the reserve for nuclear production. Also, for 1996 and 1997, we permitted FPL to record an additional $30 million in expense to the reserve for nuclear production, and to record an additional depreciation expense based on differences between actual and forecasted revenues.[29] We allowed FPL to continue the recording of these additional expenses in 1998 and 1999 by Order No. PSC-98-0027-FOF-EI.[30] We found that it was good regulatory policy to eliminate these types of items when the funds are available to do so without raising customer rates.

Subsequently, in the FPL 1999 Revenue Sharing Agreement approved by Order No. PSC-99-0519-AS-EI, we granted FPL, among other things, the discretion to record up to $100 million of additional depreciation expense each year of the three-year settlement period to reduce nuclear and/or fossil production plant in service.[31] As part of this settlement, customer rates were reduced by $350 million and a revenue cap and revenue sharing plan was established.

As a result of the FPL 2002 Settlement, approved in Order No. PSC-02-0501-AS-EI, FPL received the discretionary ability to record a depreciation expense credit of up to $125 million annually for 2002-2005.[32] The amounts recorded first went to offset the $170.3 million bottom

[29] Order Nos. PSC-95-0672-FOF-EI, issued May 31, 1995, and PSC-96-0461-FOF-EI, issued April 2, 1996, in Docket No. 950359-EI, In re: Petition to establish amortization schedule for nuclear stranded investment by Florida Power & Light Company.
[30] Order No. PSC-98-0027-FOF-EI., issued January 5, 1998, in Docket No. 970410-EI, In re: Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company.
[31] Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI, In re: Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company.
[32] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

line amortization recorded pursuant to Order No. PSC-99-0519-AS-EI, with any additional amounts recorded to a bottom line reserve to be allocated to specific accounts in the next FPL depreciation study after the term of the settlement. Among other things, the settlement reduced FPL's customer rates by $250 million and continued a revenue cap and revenue sharing plan. FPL acknowledged that it had overdepreciated its plant and a depreciation expense credit offered through the settlement would help correct the situation.

In the 2005 Settlement Order, FPL was again authorized to amortize up to $125 million annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve for years 2006-2009.[33] FPL recorded $500 million in accord with the agreement.

FRF argued in its brief that our declared policy with respect to reserve imbalances is to correct them as soon as possible without adversely impacting a company's ability to earn a fair and reasonable return.[34] FRF noted that we have also targeted overearnings in the past to book additional depreciation expense, thereby lowering reported earnings and bringing them in line with the allowed rate of return. In the instant proceeding, we are setting a new rate of return for FPL. In deciding whether to amortize the reserve imbalance as the intervenors proposed, we should also consider any negative impacts such an amortization would have on FPL's financial integrity.

OPC's proposed adjustment to address the reserve imbalance would reduce FPL's revenue requirement by approximately $311 million per year. Because rate base would be higher as a result of this adjustment, the reduction to FPL's cash flow would be offset by approximately $20 million of additional return earned on this incremental rate base. Thus, the net impact of the proposed adjustment would be a reduction to cash flow of approximately $291 million.

FRF asserted that OPC's proposed amortization would not deny FPL recovery of any capital dollars, but would only affect the timing of the collection of those dollars. Further, FRF argued that OPC's proposed amortization would not affect FPL's earnings or earned rate of return. FRF stated that metrics used to analyze financial integrity generally include measures of debt, cash flow, and interest coverage requirements.

FRF asserted that the coverage ratios (the number of times FPL's generated cash flow covers debt service) were important indicators of financial integrity. FRF stated that FPL's financial strength is such that FPL's cash flow would be sufficient to amortize $1.25 billion of the reserve surplus identified by OPC witness Pous and maintain coverage ratios that warrant an "A" rating by Standard & Poors (S&P).

[33] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[34] Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 060699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

The financial metrics affected by the proposed adjustment are the cash from operations to interest ratio (CFO/Interest) and the cash from operations to debt ratio (CFO/Debt). The debt to total capital ratio is unaffected by the proposed adjustment. FPL's corporate credit rating is single A flat from S&P, single A1 from Moody's Investor Service (Moody's), and single A flat from Fitch Ratings (Fitch). Pursuant to S&P's rating methodology, FPL's business profile is rated as excellent and its financial profile is rated as intermediate. Based on these designations, the ratings criteria published by S&P and Moody's for FPL's current credit ratings include the following cash flow metric standards.

Table 8

	S&P A rating	Moody's A rating
CFO/Interest	3.0x – 4.5x	4.5x – 6.0x
CFO/Debt	25% – 45%	22% – 30%

OPC witness Lawton testified that, while the proposed adjustment to address the reserve imbalance will decrease FPL's cash flow metrics, he did not believe it will harm the Company's financial integrity. Witness Lawton demonstrated that FPL's CFO/Interest ratio will decrease from 6.7x to 5.9x and the Company's CFO/Debt ratio will decrease from 45 percent to 40 percent. That said, this analysis does not take into account additional adjustments that will impact cash flow. However, witness Lawton argued that even if all of OPC's proposed adjustments were made, there is no basis to conclude that FPL's credit rating would fall below investment grade. FPL witness Pimentel agreed that even a two-notch downgrade for FPL would still result in a triple B plus rating, which would remain firmly investment grade. Moreover, none of the rating agencies have indicated that they would downgrade FPL's credit rating even if we denied the entire rate increase.

In this case, FPL's net reserve imbalance is a $1.2 billion surplus. The reserve surplus is of such a magnitude that its existence results in abnormal depreciation rates. Where significant reserve surpluses and deficits exist, corrective reserve transfers between accounts or amortization of the reserve imbalance should be considered. Whether the reserve imbalance is a surplus or a deficit, it violates the matching principle and represents a subsidy, and thus should be corrected.

As mentioned above, we calculated a theoretical reserve for each account within each production unit, and each transmission, distribution, and general plant account. Comparing the theoretical reserve to the book reserve resulted in various account surpluses and deficits that we netted to a bottom-line reserve surplus amount of $1.2 billion. As a result of this netting, each account's reserve is placed at its theoretically correct position. The theoretically correct reserve position is reflected in the depreciation rates contained in Table 3 and Table 6 above.

FPL, FIPUG, and OPC suggested that we transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. We agree. Accordingly, $314.2 million of the reserve surplus shall be transferred to offset the unrecovered costs associated with FPL's proposed capital recovery schedules. This reduces the reserve imbalance to an $894.6 million surplus.

FPL argued that amortization of the remaining reserve surplus over any time period other than the remaining life results in intergenerational unfairness to the ratepayers of yesterday versus those of tomorrow. OPC, on the other hand, argued that the existence of a reserve imbalance indicates that there are intergenerational inequities in that current and past customers paid more than they should have, thereby subsidizing future customers. We agree with OPC's position that intergenerational unfairness already exists, as witnessed by the existence of such a significant reserve imbalance. Therefore, we are of the opinion that amortizing the remainder of the reserve surplus is the most appropriate remedy to eliminate the intergenerational inequity the surplus created. The only question remaining is how long it should take to correct the situation.

Accordingly, we find that the remaining reserve surplus amount of $894.6 million shall be amortized over a four-year period. This is consistent with our policy with respect to reserve imbalances, which has been to correct them as soon as possible without adversely impacting the company's ability to earn a fair and reasonable return.[35] We find that there is substantial evidence in the record to show that the company's ability to earn a fair and reasonable return will not be adversely affected. Furthermore, our decision is consistent with past orders in which we have amortized reserve imbalances over periods shorter than the remaining life.[36] And we note that we will be reviewing FPL's depreciation reserve again when FPL files its next depreciation study.

In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010. As part of FPL's next depreciation study, to be filed no later than March 16, 2013, FPL's reserve position will be reviewed and assessed for any other necessary action.

Implementation date for revised depreciation rates, capital recovery schedules and amortization schedules

FPL proposed an implementation date of January 1, 2010. All the parties, except SFHHA, agreed with FPL's proposed implementation date. SFHHA argued that the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules should correspond with the implementations of rates resulting from this proceeding. We disagree with SFHHA's proposed implementation date. The implementation date for the

[35] Order No. PSC-01-2270-PAA-EI, issued on November 19, 2001, in Docket No. 010699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

[36] Order No. PSC-96-0461-FOF-EI, issued on April 2, 1996, in Docket No. 950359-EI, In Re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company; Order No. PSC-06-0307-FOF-TP, issued April 20, 2006, in Docket No. 041269-TP, In re: Petition to establish generic docket to consider amendments to interconnection agreements resulting from changes in law, by BellSouth Telecommunications, Inc.; and Order No. PSC-98-1723-FOF-EI, issued on December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation.

revised depreciation rates, capital recovery schedules, and amortization schedules shall be January 1, 2010, because FPL data and related calculations abut the January 1, 2010 date.

FOSSIL DISMANTLEMENT COST STUDY

Annual dismantlement provision

FPL's 2008 fossil dismantlement study filed in this proceeding indicates there is a need to adjust FPL's current annual fossil dismantlement accrual, which is currently set at $15,321,113. The current dismantlement study represents an update of FPL's base dismantlement costs, contingency, and inflation forecasts. FPL contends an annual accrual of $20,180,368 is required to meet its fossil dismantlement needs. We analyze and critique FPL's 2008 fossil dismantlement study below.

The current-approved annual dismantlement provision shall be revised to reflect the Company's updated base cost estimates of dismantlement, inflation rates, and contingency costs. Any revised annual fossil dismantlement accrual shall take effect January 1, 2010. Table 9 on the following page details FPL's fossil dismantlement cost by plant site.

Table 9

FOSSIL DISMANTLEMENT COST ESTIMATES		
	2007 Study Current Costs	2008 Study Current Costs
	($)	($)
Cape Canaveral	12,953.491	16,642,848
Cutler	8,035,610	10,424,803
Fort Lauderdale	18,956,572	25,524,535
Ft. Myers	22,877,762	29,598,540
Manatee	53,698,856	65,118,814
Martin	57,337,705	76,887,456
Port Everglades	52,594,168	61,149,529
Putnam	9,403,254	11,146,862
Riviera	13,583,544	15,070,232
Sanford	28,650,916	35,681,288
Scherer	37,391,063	43,744,940
St. Johns River Power Park	19,548,345	24,802,975
Turkey Point	18,323,729	25,825,396
West County Energy Center	-	22,707,813
DeSoto Solar	-	1,365,069
Space Coast Solar	-	724,875
St. Lucie Wind Turbines	-	584,770
Total*	**353,355,015**	**467,000,745**

* Cost estimate totals were subject to rounding for some of the plant site/units.

Corrective reserve measures

FPL's 2008 fossil dismantlement study contains proposed adjustments to correct reserve imbalances that exist for certain units. These imbalances arise when there are discrepancies between the actual dismantlement reserve and the theoretical reserve indicated in the dismantlement study. FPL proposed that reserve surpluses for the Cape Canaveral and Riviera plants be transferred to the Cutler, Manatee, Martin, Port Everglades, Sanford, Scherer, St. Johns River and Turkey Point plants. Although FPL did not file updated reserve transfers, we were able to calculate the appropriate transfer amounts, which are shown in Table 10, including the companies updated inflation figures.

We have consistently approved reserve transfers in fossil dismantlement studies. FPL's last reserve transfers were approved by Order No. PSC-08-0095-PAA-EI, issued on February 14, 2008, in Docket No. 070378-EI, In Re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company. We have reviewed FPL's proposed reserve transfers, and consistent with our precedent, we believe they are reasonable. However, FPL's dismantlement cost estimates shall be updated to reflect the February 2009 Global Insight inflation forecasts. Accordingly, we approve the corrective reserve reallocations shown in Table 10 below.

Table 10

THEORETICAL RESERVE RE-ALLOCATIONS FOR JANUARY 1, 2010				
Site	**Actual Reserves December 31, 2009**	**Theoretical Reserves**	**Reserve Transfers**	**Restated Reserve for 1/1/2010**
Cape Canaveral	$17,654,087	$16,970,239	$(1,269,977)	$16,384,110
Cutler	11,429,097	13,168,448	144,749	11,573,846
Manatee	36,930,092	46,480,891	794,816	37,724,908
Martin	35,623,068	39,988,999	363,331	35,986,399
Port Everglades	54,604,976	74,237,570	1,301,674	55,906,650
Riviera	18,943,435	15,349,799	(3,593,636)	15,349,799
Sanford	5,987,502	6,267,665	23,315	6,010,817
Scherer	30,939,801	42,933,155	998,085	31,937,886
St. Johns River	18,825,872	27,761,363	743,609	19,569,481
Turkey Point	17,216,106	23,152,609	494,034	17,710,140
Total Reserves*	**$248,154,036**	**$306,310,738**	**$0**	**$248,154,036**

* Reserve transfers were subject to rounding for some of the plant site/units.

Annual provision for dismantlement

By Order No. 24741,[37] we established the methodology for accruing the costs for dismantlement of fossil-fueled production plants. The methodology, codified in Rule 25-6.04364, F.A.C., is dependent on three factors: estimated base costs for dismantlement, projected inflation, and a contingency factor. Electric companies are required to file site-specific dismantlement studies at least once every four years from the submission date of the previous study unless otherwise required by Commission order.

FPL filed its last updated dismantlement cost study with associated annual accrual proposals in 2007. We approved this study and associated fossil dismantlement accruals by Order No. PSC-08-0095-PAA-EI.[38] In this order, we also directed FPL to file its next fossil fuel dismantlement study concurrently with its comprehensive depreciation study on or about March 17, 2009.

[37] Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, In Re: Investigation of the Ratemaking and Accounting Treatment for the Dismantlement of Fossil-Fueled Generating Stations.
[38] Order No. PSC-08-0095-PAA-EI, issued February 14, 2008, in Docket No. 070378-EI, In re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company.

The dismantlement cost estimates in the current study are based on site-specific analysis and reflect an increase of approximately 32 percent from the 2007 cost estimates. The major drivers of the increase in cost include: (1) addition of new plant, (2) increases in the equipment rental component of labor rates, and (3) increased fuel oil tank removal costs. The dismantlement costs for Martin Solar, Desoto Solar, and Space Coast Solar plants will be recovered through the ECRC.

Dismantlement accruals are based on current cost estimates, escalated to future costs of the estimated date of dismantlement. The future costs, less accumulated dismantlement reserves, are discounted over the remaining life of each plant and plant site. We established the methodology for calculating annual accruals for the dismantlement fossil-fueled production plants by Order No. 24741. FPL's fossil dismantlement study as filed contained August 2008 inflation factors and assumed dismantlement of plants will begin five years after retirement. Inflation rates are used to escalate the current costs to the expected future amount that will be needed to pay for dismantlement. We requested, and were provided, updated inflation factors to reflect current market rates. The updated inflation rates are from the February 2009 Global Insight edition.

Our approved levelized annual accrual of $18,468,387 (including solar) is based on FPL's site-specific dismantlement cost estimates and a 16 percent contingency factor, with two modifications. First, we used the February 2009 inflation factors published by Global Insight for 2010 though 2013. Second, our analysis incorporated changes in the retirement dates of certain units in accord with our decisions above. We applied the jurisdictional separation factors for 2010 to the levelized annual accrual of $18,014,571 that excludes the solar units. Our approved retail annual accrual amount for 2010 is $17,660,832 (excluding solar), which reflects an increase of $2,640,568 over the amounts from FPL's last dismantlement study. Our calculations of the retail annual accrual amounts and incremental increase are shown in Table 11. FPL's 2008 site-specific dismantlement costs are shown in Table 12. Accordingly, this change to the fossil dismantlement annual accrual impacts the 2010 and 2011 accumulated depreciation and depreciation expense as set forth below.

Table 11
2010 Projected Test Year – Commission Approved

Functional Description	**2007 Current Accrual**	**Required Increase in Cost of Service**	**Commission Approved 2010 Annual Accrual**
Fossil	$8,966,504	$755,421	$9,741,745
Other Production excluding Solar	$6,354,609	$1,918,216	$8,272,825
Total Excluding Solar	$15,321,113	$2,693,457	$18,014,570
Jurisdictional Separation Factor		98.036379%	98.036379%
Retail Annual Accrual Amounts		**$2,640,568**	**$17,660,832**

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Table 12

FLORIDA POWER AND LIGHT COMPANY EFFECTIVE ACCRUAL JANUARY 1, 2010			
Plant Site	**2007 Current Annual Accrual****	**Commission Final Approved Annual Accrual**	**Final Change in Annual Accrual**
	($)	($)	($)
Cape Canaveral	434,779	252,203	-182,576
Cutler	216,262	333,801	117,539
Fort Lauderdale	985,269	1,251,191	265,922
Fort Myers	1,161,985	1,317,305	155,320
Manatee	2,255,726	2,559,415	303,689
Martin	2,327,547	2,533,098	205,551
Port Everglades	2,566,987	2,802,360	235,373
Putnam	339,106	405,297	66,191
Riviera	321,232	89,182	-232,050
Sanford	1,374,909	1,493,396	118,487
Scherer	1,755,506	1,634,157	-121,349
St. Johns River Power Park	807,788	869,586	61,798
Turkey Point	774,017	1,111,193	337,176
Martin Solar	0	346,160	346,160
West County Energy Center	0	1,332,348	1,332,348
St Lucie Wind Turbines	0	30,038	30,038
DeSoto Solar	0	72,712	72,712
Space Coast Solar	0	34,944	34,944
Total Dismantlement Provision	***15,321,113**	***18,468,387**	**3,147,274**
Less accrual for solar units recovered through the ECRC clause			453,817
Increase in cost of service due to increase in non-solar dismantlement accrual			***** 2,693,457**

* Annual accruals were subject to rounding for some of the plant site/units.

** Annual accrual per approved by Order No. PSC-08-0095-PAA-EI, issued on February 14, 2008, in Docket No. 070378-EI, In Re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company.

***Net increase in fossil dismantlement accrual.

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In conclusion, the appropriate system annual provision for dismantlement is $18,468,387 (including solar), and the retail annual accrual amounts for 2010 is $17,660,832 (excluding solar). This reflects an increase of $2,640,568 over the amounts from FPL's last dismantlement study. These accruals reflect current estimates of dismantlement costs on a site-specific basis, inflation estimates as of February 2009, a 16 percent contingency factor, and changes in retirement dates in accordance with this Order.

Greenfield status

In his testimony, OPC witness Pous objected to the extent of FPL's fossil dismantlement approach. He contended that FPL's dismantlement assumptions "assumed a 100% probability of the worst case scenario, that being full demolition and site restoration." Witness Pous asserted that FPL is not legally required to restore its plant sites to a "greenfield" condition. During cross-examination, FPL witness Ousdahl stated she believed that site restoration in terms of greenfield means "park-like." She cited the Company's dismantlement of its Palatka plant as an instance where site remediation was to greenfield status. AIF supported FPL's position. In its brief, AIF stated that FPL witness Ousdahl clearly described the cost components included in FPL's 2008 fossil dismantlement study. AIF stated that intervenor witnesses Pous and Pollock provided no basis for the disallowance of FPL's 2008 fossil dismantlement study as presented, including site restoration to greenfield status upon retirement.

Rule 25-6.04364, F.A.C., is our dismantlement rule. Of particular interest to this issue are subparts 2 (b) and (c):

> (2)(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or useable condition.
>
> (2)(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service.

We find that FPL's site restoration assumptions in its 2008 study comport with both our rule and Commission precedent in previous dismantlement proceedings. Accordingly, we find that the assumptions FPL made in its 2008 dismantlement study with regards to site restoration site restoration assumptions by definition are reasonable.

Dismantlement studies

By Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, In Re: Investigation of the Ratemaking and Accounting Treatment for the Dismantlement of Fossil-Fueled Generating Stations (Order No. 24741), we established the methodology for accruing the costs for dismantlement of fossil-fueled production plants. The methodology, codified in Rule 25-6.04364, F.A.C., is dependent on three factors: estimated base costs for dismantlement, projected

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inflation, and a contingency factor. As explained above, electric companies are required to file site-specific dismantlement studies at least once every four years from the submission date of the previous study unless otherwise required by our order.

FPL's fossil dismantlement study contains two types of assumptions. First, the study includes general assumptions that are applicable to all units and sites, such as provisions for site security and management personnel. Second, for each unit, the study includes site-specific assumptions, which are intended to capture unique characteristics of an individual plant site. Examples of site-specific assumptions may also include such things as the extent of asbestos abatement required for a given unit, and whether controlled blasting of chimneys can be done.

We find that FPL's dismantlement study complies with our dismantlement rule and is in accord with prior dismantlement studies. Based on our review of the study and its supporting documentation, we believe that the company adequately takes into consideration factors that are unique to specific units when estimating dismantlement costs. As such, it appears that FPL has considered alternative demolition techniques and incorporated them into the study. FPL should continue to consider whether alternative demolition approaches are reasonable in future studies, as it has in the past. Absent specific references, it is unclear what aspects of FPL's study OPC believes are deficient or unsupported. Accordingly, at this time we do not believe the record supports the need to require FPL to file analyses of alternative demolition approaches.

RATE BASE

Calculation of working capital allowance

According to FPL witness Ousdahl, our current practice for clause over- and under-recoveries is not equitable. She testified that:

> The Commission has not permitted FPL to remove the liability from working capital even though FPL compensates customers by paying interest on the over-recovery through the cost recovery clauses. This is inconsistent with the treatment of underrecoveries, where the Commission has previously required FPL to remove the asset from working capital.

Witness Ousdahl argued that this Commission should acknowledge that base rates should never include the cost of capital associated with clause over- or under-recoveries, as such costs are already provided for in the clause rate itself. She further argued that the regulatory liability associated with projected over-recoveries should be removed from working capital.

OPC stated that over-recoveries represent funds the Company owes customers and if they excluded from working capital, customers would be providing interest the company returned in the clause. OPC further stated that the under-recoveries are collected from the customers at the commercial paper rate. In addition, if a clause under-recovery is included in base rates, the company will receive a double return on the under-recovery.

OPC argued that the Commission's practice has been to exclude fuel under-recoveries, which are assets, from Working Capital, and to include over-recoveries, which are liabilities. Furthermore, the rationale for including over-recoveries as a reduction to working capital is to provide the Company with an incentive to make its projections for the cost recovery clause as accurate as possible and avoid large over-recoveries.[39]

We agree with the assessment of OPC as to how we have handled fuel over-recoveries in calculating the working capital allowance in prior rate case proceedings. In the Company's last rate proceeding, its fuel over-recovery was included in the calculation of the working capital allowance. There is no compelling evidence in the record that indicates our policy should be changed. Utilities should strive to reasonably project expenses so as to avoid over-collecting from customers. Therefore, the over-recovery that shall be included in the calculation of the working capital allowance for 2010 is $101,971,000.

Advanced Metering Infrastructure (AMI)

FPL plans to install smart meters over a five year period. The meters will have more capabilities than the meters currently installed. The new meters will be equipped with two-way communications, remote reading, connection, and disconnection capabilities and will be able to collect data regarding consumption at predetermined intervals. The installation will be for residential and small/medium business accounts. The meters will provide both operational and service improvements. The operational improvements include a reduced need for meter readers. The service improvements include more customer usage information and reductions in the number of calls to the company. The meters have a life expectancy of 20 years.

Below is Table 13 that summarizes the number of meters being installed, capital costs, O&M costs, O&M savings and net O&M savings.

Table 13

Deployment	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**
Meters (Thousands)	170	1,128	1,099	1,076	873	4,346
Capital (Millions)	$43.7	$168.5	$158.7	$151.5	$122.5	$645
O&M (Thousands)	$2,274	$6,883	$8,910	$11,882	$10,458	
Savings (Thousands)	($167)	($418)	($4,700)	($18,203)	($30,401)	
Net O&M (Thousands)	$2,106	$6,465	$4,210	($6,321)	($19,943)	

[39] Order No. 12663, issued November 7, 1983, in Docket No. 830012-EU, In re: Petition of Tampa Electric Company for an increase in rates and charges and approval of a fair and reasonable rate of return, pp. 14-15; and Order No. PSC-93-0165-FOF-EI, issued March 29, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company, p. 38.

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FPL witness Santos testified that the implementation of AMI will help to modernize the grid. The implementation of AMI will have $645 million in capital costs and once fully implemented will have an annual cost savings of $36.9 million. Beginning in 2012, the O&M savings are greater than the O&M costs associated with AMI. Beginning 2013, the net O&M savings exceed $30 million annually. Witness Santos testified that the savings from smart meters are not directly proportional to the installations. Witness Santos testified that AMI is a long-term project in which savings are realized after several complex, interdependent components and processes are fully developed, tested and implemented and deployment at the FPL regional work area is achieved.

SFHHA witness Kollen testified that the savings from the meters and the costs should be aligned. Witness Kollen proposed including 16.9 percent of the estimated $36 million in savings into the test year. The witness further testified that it is unreasonable to have the ratepayers pay 16.9 percent of the total expenditures for AMI in the test year while only receiving 1.2 percent of the projected savings.

We believe SFHHA's arguments are unfounded. While we agree the savings are not in the test year, it would be inappropriate to move costs or savings from outside of the test year into the test year. This project spans several years, and FPL plans to make significant investments outside of the test year. FPL has not front loaded costs for this project. AMI implementation will ultimately give customers more control over their energy usage.

Accordingly, we find that the costs for AMI implementation are appropriate and have properly been included in rate base for the test year. As seen in the chart above, the Company will continue making investments outside of the test year. The project will lead to increased savings. The investment will help modernize the grid and help the Company provide better service to its customers. If the savings become too great, and the Company earns a return outside its authorized rate, we may call FPL in for an earnings review.

FPL shall provide annually a progress report on implementation of smart meters in the Energy Conservation Cost Recovery docket. The report shall include a detailed description of how FPL intends to utilize smart meters to allow customers to better manage their energy consumption, including new programs or rate offerings associated with smart meters.

Levels of plant in service

We were asked to address whether FPL's requested $28,288,080,000 levels of plant in service was appropriate. As explained below, we do not find that it is. FPL agreed with OPC's position to remove the long-term transmission service contracts. OPC witness Brown provided revised adjustments. However, in some instances her calculations were less than FPL's adjustments as shown in Exhibit 378. OPC chose to adopt the adjustments of FPL provided by witness Ender as proper adjustments to be made to rate base, operating revenues, and expenses.

SFHHA witness Kollen's calculations established the 2009 total reduction of 19 percent or $529 million, by annualizing the actual decrease of the first four months of capital expenditures in the amount of $170 million. Witness Kollen did not provide any supporting documentation to substantiate annualizing only four months of data for capital expenditures. There were no comparative analyses of historical data to add credibility to SFHHA's proposed overstatement of 2009 through 2011 capital expenditures. FPL outlined its capital expenditures by business units rather than by FERC accounts. SFHHA used the annualization based on business units without obtaining the necessary documentation from FPL that would have linked the reductions to the functional accounts in the MFRs. Therefore, we find that SFHHA's adjustments for 2009 through 2011 using the first four months of 2009 capital expenditures were not supported by adequate documentation.

FPL witness Ousdahl provided a schedule in her rebuttal testimony that identified additional Company adjustments as stated below. In addition, she provided a late filed exhibit that identified the applicable plant account/function the adjustments would impact.

(1) Item 21 of Exhibit 358 identified the jurisdictional adjustment to transmissions services for the removal of the long-term transmission service contracts as a reduction to plant in service in the amount of $386,896,000.

(2) Item 4 of Exhibit 358 reflected an adjustment for anticipated capital expenditures expected by DOE in 2010 due to the nuclear fuel settlement agreement. This resulted in a jurisdictional reduction in the amount of $25,866,000 for 2010.

(3) Item 12 of Exhibit 358 reflected a reduction to plant in service for a correction of an error related to the Customer Information System III (CIS) in the amount of $3,301,000 for 2010.

As discussed below, a reduction was made to aircraft expenditures for plant in service in the amount of $53,268,205 for 2010.

During the cross-examination of FPL witness Barrett, he was asked whether the deferred projects listed on Exhibit 418 were included in the $91 million reduction as shown in Exhibit 386. He stated that the projects were deferred from the 2010 projected test year. He further clarified that "Exhibit 418 reflected plant in service, accumulated depreciation, Construction Work In Progress (CWIP), and depreciation for the delayed substations." The deferred substation projects show a reduction to plant in service for 2010 in the amount of $7,276,000.

As discussed above, a capital recovery schedule, as shown in Table 1, was established for the near-term retirements of Cape Canaveral and Riviera power plants, the St. Lucie and Turkey Point nuclear uprate projects, and the AMI meter project. The total estimated investment of the near-term retirements as of December 31, 2009 is shown as $774,610,189. In addition to the capital recovery schedule, a corresponding reduction shall be made to plant in service and accumulated depreciation to remove the estimated investment for the planned near-term retirements. Therefore, plant in service and accumulated depreciation for the 2010 test year shall be reduced by $774,610,189.

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As shown in Table 14 below, we identified all the adjustments to plant in service for 2010 as provided in the record. Based on a review of the parties' positions and adjustments, plant in service shall be reduced for the 2010 test year by $1,251,217,394.

TABLE 14

2010 Plant In Service Adjustments				
Description	FPL	OPC	SFHHA	Commission
Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services		($373,423,000)		
EXH 358-Issue 4-DOE Settlement	($25,866,000)	0		($25,866,000)
EXH 358-Issue 12 CIS III	($3,301,000)	0		($3,301,000)
EXH 358-Item 21-Transmission Services–jurisdictional factor	($386,896,000)	0	0	($386,896,000)
EXH 418-Deferred Projects	0	0	0	($7,276,000)
Issue 94 Aviation Costs	($53,268,205)	0		($53,268,205)
Issue 50: SFHHA Capital Expenditures	0		($784,000,000)	0
Issue 19A: Table 1				($774,610,189)
Total Reductions	($469,331,205)	($373,423,000)	($784,000,000)	($1,251,217,394)

In summary, based on the reductions reflected in Table 14 above, the appropriate level of plant in service for the 2010 test year is $27,036,862,606.

Levels of accumulated depreciation

We examined accumulated depreciation records of the Company for 2010 to determine the appropriate projected test year amount. We made several adjustments, including those agreed to by FPL and the parties, issues relating to the 2009 depreciation study, fossil dismantlement study, reserve surplus, GBRA, deferred/delayed projects, aviation, and changes based on the jurisdictional separation of long-term transmission contracts.

As shown in Table 15 on the following page, we identified all the adjustments to accumulated depreciation for 2010 as provided in the record.

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TABLE 15

2010 PROJECTED TEST YEAR-ACCUMULATED DEPRECIATION			
Description	FPL's proposed	OPC's proposed	Commission approved
Accum. Depreciation Per FPL Filing	$12,590,521,000	$12,590,521,000	$12,590,521,000
Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services			
EXH 358-Issue 4-DOE Settlement	($252,000)	0	($252,000)
EXH 358-Issue 12 CIS III	($130,000)	0	($130,000)
EXH 358 Issue 16 Account 354 correction	($1,734,000)		($1,734,000)
EXH 358-Item 21-Transmission Services–jurisdictional factor	($144,299,000)	0	($144,299,000)
EXH 418-Deferred Projects	0	0	($114,000)
Issue 94 Aviation Costs	($27,853,907)	0	($27,853,907)
Issue 19C and 19D: Depreciation Study			($41,367,500)
Issue 19E: Reserve Surplus			($111,848,000)
Issue 42: Fossil Dismantlement Study			$1,320,284
Issue 50: Near-term Investment for Retirements			($774,610,189)
Total Reductions	($174,268,907)	($414,924,000)	($1,100,888,312)
Accumulated Depreciation Levels	$12,416,252,000	$12,175,597,000	$11,489,632,688

Accordingly, the appropriate adjustment for the 2010 test year is $1,100,888,312.

Adjustment to CWIP

FPL proposed an adjustment to CWIP for the 2010 projected test year for the Florida EnergySecure Line (gas pipeline). The Company's proposed adjustment is not appropriate. On October 6, 2009, we denied FPL's petition to determine need for the gas pipeline. We determined that FPL had not adequately shown that the proposed gas pipeline was the most cost-effective option.[40] Accordingly, we ordered FPL to revise its request for proposals based on its identified gas transportation needs and provide a copy to our staff for review prior to its issuance. Based on these actions, the capital expenditures for the gas pipeline shall not be reflected through CWIP - AFUDC nor reported to this Commission on the Company's Monthly Earning Surveillance reports.

[40] Order No. PSC-09-715-FOF-EI, issued October 28, 2009, in Docket No. 090172-EI, In re: Petition to determine need for Florida EnergySecure Pipeline by Florida Power & Light Company.

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Levels of Construction Work in Progress (CWIP)

FPL stated that the appropriate level of CWIP for the 2010 projected test year, including the adjustments from Exhibit 358 (KO-16), should be $691,380,000. OPC stated that the appropriate levels of CWIP should reflect the adjustments provided in Exhibit 248 (SLB-26 Revised) regarding the appropriate jurisdictional factors. OPC further stated that the appropriate jurisdictional amount for 2010 should be $692,754,000.

We agree with the Company's calculations for the impact of the jurisdictional separation factors as shown in Item 21-Transmission Services. FPL witness Ousdahl provided additional adjustments in Exhibit 358 (KO-16) which impacted CWIP as identified in Table 16 below, including (1) Item 4-DOE Settlement nuclear spent fuel agreement), and (2) Item 12-CIS Plant III for an error in projection to plant in service. However, witness Barrett's late-filed exhibit was entered into the record, which included projects deferred from the 2010 test year. Witness Barrett explained that Exhibit 418 (2010-2011 Deferred Projects) included deferred projects which resulted in reductions to the 2010 test year to plant in service, accumulated depreciation, CWIP, and depreciation expense. This exhibit included a reduction in CWIP for 2010 in the amount of $4,565,000. The overall adjustments are provided in Table 16 below.

TABLE 16

CONSTRUCTION WORK IN PROGRESS -2010 ADJUSTMENTS			
Description	Company proposed	OPC proposed	Commission Approved
Exhibit 358-Item 21-Transmission Services	($18,623,000)	($14,777,000)	($18,623,000)
Exhibit 358-Item 4-DOE Settlement	(828,000)	0	(828,000)
Exhibit 358-Item 12-CIS Plant III	3,301,000	0	3,301,000
Exhibit 418-Deferred Projects	0		(4,565,000)
Total deductions	($16,150,000)	($14,777,000)	($20,715,000)

We find that the appropriate level of CWIP for the 2010 projected test year is $686,815,000, which is a reduction of $20,715,000 from FPL's requested level.

Levels of Property Held for Future Use

As discussed earlier in this Order, OPC stated that Exhibit 378 reflected the proper adjustments to be made to rate base, operating revenues and expenses. We compared OPC witness Brown's Exhibit 248 with FPL witness Ender's Exhibit 378 and saw there were differences in some of the adjustments. Even though there are differences in the parties adjustments, OPC chose to use FPL witness Ender's adjustments. The overall rate base reduction for 2010 is $261,720,000. Exhibit 378 shows that the Company reduced property held for future use for 2010 in the amount of $4,200,000.

We find that the appropriate level of property held for future use for 2010 is $70,302,000. Accordingly, the proposed level of property held for future use for 2010 shall be reduced by $4,200,000.

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Accrual of Nuclear End of Life Materials and Supplies

Order No. PSC-02-0055-PAA-EI addresses (1) FPL's petition for the approval of annual accruals for nuclear decommissioning; (2) FPL's accumulated amortization; and (3) the appropriate method of recovery for the last core of nuclear fuel for FPL. The order explained FPL's position on end-of-life material and supplies inventories and last core as follows:

> FPL believes EOL M & S (end of life material and supplies) inventories should be considered part of nuclear decommissioning since the costs relate to the time each nuclear site will cease operation. Further, FPL asserts that the annual expense/reserve accruals associated with the EOL M & S inventories represent the recovery of amounts that will have already been expended during the operating life of each nuclear unit and thus do not require a cash outlay at the time of decommissioning. Therefore, FPL concludes that there is no need to fund these amounts.
>
> FPL considers the Last Core cost to be a result of final shut down of the nuclear reactor, equating to an unrecovered cost remaining at the end of the unit's life.

The order also addressed our request that FPL address the amortization status of end of life material and supplies and last core costs in subsequent decommissioning studies so the related annual accruals could be revised, if warranted. The order further stated that "in the event of industry restructuring, treatment of the Last Core unfunded reserve should follow the same treatment afforded nuclear decommission." Based on this order, we find that this base rate proceeding is not the appropriate docket within which to address the increase for end of life nuclear fuel last core and material and supplies.

In conclusion, we find that the 2010 accrual of nuclear end of life materials and supplies and last core nuclear fuel is appropriate based on the 2005 Settlement Order. However, the additional expense for 2010 and 2011 in the amount of $6 million for end-of-life nuclear fuel last core and $137,000 end of life materials and supplies shall be removed from the applicable accounts of this base rate proceeding and addressed when the Company files its 2010 Nuclear Decommissioning Study.

Nuclear fuel included in rate base

FPL included the nuclear fuel balance in net plant and, therefore, included in the calculation of rate base. Based on the change in accounting rules, the benefit of off-balance sheet financing is no longer available, and the nuclear fuel balance is a part of FPL's consolidated balance sheet. Further, bond rating agencies now include the debt that financed the nuclear fuel as part of FPL's overall debt. Finally, including nuclear fuel in rate base is analogous to including fuel inventory in working capital and, therefore, in rate base. For these reasons, we approve FPL's proposed treatment of nuclear fuel. Accordingly, the nuclear fuel assets shall be capitalized and included in rate base for the 2010 projected test year.

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We recognize that this treatment increases the revenue requirement in comparison to the previous (leasing) treatment. This is because the nuclear fuel assets are financed at the overall cost of capital instead of the specific debt rate for commercial paper.

Levels of Nuclear Fuel

Based on our review of OPC Exhibit 248, we found that OPC's net Nuclear Fuel reduction for the 2010 test year was $39,000. We made a similar review of FPL's Exhibits 358 and Exhibit 378 (JAE-11), and found that FPL's net nuclear fuel reduction for the 2010 projected test year was $3,771,000. As discussed above, OPC agreed with FPL's final reductions. Therefore, we agree with both parties that FPL's reduction for the 2010 test year is appropriate. Accordingly, the appropriate level of nuclear fuel for 2010 is $370,962,000. This results in a reduction of $3,771,000.

Unamortized balance of Glades Power Park

FPL contended that the unamortized balance of the FPL Glades Power Park (FGPP) should be included in rate base. The Company stated that in Order No. PSC-09-0013-PAA-EL, issued on January 5, 2009, in Docket No. 070432-EI, we granted FPL recovery of the FGPP costs and provided for amortization of the $34.1 million of costs over a five-year period beginning on January 1, 2010.[41] The other parties to the rate case proceeding took no position on this issue.

We agree with the Company. Accordingly, the unamortized balance of FGPP in the amount of $34.1 million shall be included in rate base and amortized over five years.

Levels of working capital

In Table 17 below, we list all of the adjustments to working capital as provided by FPL and OPC. As discussed above, FPL's adjustments were identified in Exhibit 358 (KO-16) and are shown in the table as a $7,777,000 increase to working capital. Item 21-Transmission Services jurisdictional factor was discussed above, and the table reflects the applicable portion of the $261,720 million reduction which impacted working capital. Each adjustment represents a correction of an error to rate base by the Company. OPC contended that the 2010 adjustment to working capital should be $41,763,000. However, FPL argued that the adjustment to 2010 working capital should be an increase of $7,777,000. We believe that the net over-recovery that was removed by FPL, as discussed above, should be included in the calculation of the working capital allowance. The inclusion of over-recoveries in working capital is an ongoing practice of this Commission. Therefore, the 2010 calculation of the working capital allowance shall be increased by $101,971,000. Also, as we discuss below, rate case expense shall be removed from working capital for the 2010 test year in the amount of $2,948,000. Accordingly, the overall effect results in reductions for the 2010 test year in the amount of $97,194,000, as reflected in Table 17 below.

[41] Order No. PSC-09-0013-PAA-EI, issued January 5, 2009, in Docket No. 070432-EI, In re: Petition for authority to use deferral accounting and for creation of a regulatory asset for prudently incurred preconstruction costs associated with development of clean coal project by Florida Power & Light.

TABLE 17

2010 Working Capital Adjustments			
Description	FPL	OPC	Commission
Item 8 - Bad Debt (EXH 358)	$584,000	0	$584,000
Item 13 - Storm Liability (EXH 358)	1,809,000	0	1,809,000
Item 14 - Fuel Inventory	1,685,000	0	1,685,000
Item 21 - Transmission Services	3,700,000	($41,763,000)	3,700,000
Issue 46 - Over-Recovery	0	0	(101,971,000)
Issue 122 - Rate Case Expense			(2,948,000)
Total Working Capital Reduction	$7,777,000	($41,763,000)	($97,141,000)

In summary, as reflected in Table 17 above, the appropriate reduction for the 2010 working capital allowance is $97,141,000. Therefore, the appropriate level of working capital for the 2010 test year is $112,121,000.

Requested rate base

We find that the appropriate 2010 projected test year rate base is $16,787,429,918, which is a reduction of $276,156,082 from FPL's requested level, as shown below in Table 18 below.

TABLE 18

Jurisdictional Amount for 2010 Rate Base				
	FPL	OPC	SHHA	Commission
Utility Plant-In-Service	27,818,749,000	27,914,655,000	27,504,000,000	27,036,862,606
Accumulated Depreciation	12,416,252,000	12,175,597,000		11,489,632,688
Net Plant-In Service	15,402,497	15,739,058,000		15,547,229,918
CWIP	691,380,000	692,754,000		686,815,000
Property Held for Future Use	70,302,000	70,432,000		70,302,000
Nuclear Fuels	370,962,000	374,772,000		370,962,000
Net Utility Plant	16,535,141,000	16,877,016,000		16,675,308,918
Working Capital	217,040,000	167,502,000		112,121,000
Total Rate Base	16,752,180,637	17,044,518,000	16,511,586,000	16,787,429,918

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COST OF CAPITAL

Accumulated deferred taxes

As defined in Order No. PSC-09-0283-FOF-EI[42] issued in the recently completed Tampa Electric Company rate case:

> ADITs [Accumulated Deferred Income Taxes] represent the income tax component resulting from the application of the income tax rate to temporary differences at each balance sheet date. Deferred tax expense reflects the period to period change in ADITs. Because the financial statements reflect accrual accounting, the income tax expense calculation must reflect the liability for income taxes payable in the future as a result of transactions recorded in the current financial statements. Deferred income taxes are generated when ratepayers pay income tax expenses in rates prior to the Company actually being required to make those payments to the U.S. Treasury. Deferred income taxes are included in capital structure because these funds are used by the Company in the provision of utility electric service and should be reflected in the utility's regulated capital structure. The purpose of deferred income tax accounting is to reflect in the financial statements the tax effects (both current and deferred) of assets, liabilities, revenues, and expenses recorded on the financial statements. In the regulated environment, the process of recording deferred income taxes on temporary differences is often referred to as "normalization." Recognizing zero cost deferred taxes in the capital structure (normalization) reduces the overall rate of return charged to ratepayers. In ratemaking, the ADIT balance is a zero cost source of capital in the cost of capital computation, thereby sharing the benefit of the reduced financing costs with ratepayers.

Financial Accounting Standards Board (FASB) Statement No. 109 (SFAS 109)[43] requires a company to recognize a deferred tax liability or asset for the deferred tax consequences of temporary differences. The correct amount of ADITs is the result of various adjustments to the original MFR Schedules.

FPL's original MFR Schedules showed a jurisdictional ADITs balance of $2,723,327,000 for 2010. As a result of "bonus depreciation" made available by the American Recovery and Reinvestment Act of 2009, FPL's balance of jurisdictional ADITs increased to $2,886,174,000 for 2010. The Company's revised MFR Schedule D-1a reflected a balance of jurisdictional ADITs of $2,890,553,000 for 2010. This additional adjustment in the amount of ADIT was the

[42] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

[43] Accounting for Income Taxes, Statement of Financial Accounting Standards No. 109 (Financial Accounting Standards Board, 1992) Cross Reference: Income Taxes, FASB ASC 740 (Topic 740 of the Financial Accounting Standards Board Accounting Standards Codification). The Codification is the single source of authoritative nongovernmental U.S. generally accepted accounting principles (US GAAP) effective for interim and annual periods ending after September 15, 2009.

result of subsequent rate base and cost of capital adjustments made by the Company related to the removal of aviation expenses.

FPL witness Ousdahl recommended certain adjustments to the balance of ADITs originally proposed by the Company for the 2010 projected test year. FPL proposed an adjustment to tax depreciation for 2009 to reflect the impact of the Stimulus Bill of the American Recovery and Reinvestment Act of 2009. The Stimulus Bill allowed businesses to immediately depreciate 50 percent of the cost of a depreciable property purchased and placed in service in 2009. (26 USC §168(k)) Consistent with the IRC §168(k),[44] FPL utilized the special depreciation allowance in addition to Modified Accelerated Cost Recovery System (MACRS) tax depreciation allowed on its federal tax returns. FPL increased the tax depreciation by $884 million in 2009. However, in addition to recognizing the bonus depreciation adjustment, FPL also corrected an error that resulted in a decrease in the accumulated deferred income tax liability. The net result of these adjustments increased the balance of ADITs to $2,890,553,000 for 2010.

SFHHA witness Kollen recommended that the appropriate amount of ADITs was $3,313,373,000 for the projected 2010 test year. Witness Kollen offered reasons why the balance of ADITs should be increased. First, witness Kollen asserted that the Company inappropriately reduced the balance of ADITs included in the proposed capital structure by $168,598,000 for the effects of FASB Interpretation No. 48 (FIN 48).[45]

FIN 48 is an interpretation of FASB SFAS 109 that clarifies the accounting for uncertainty in income taxes. FIN 48 requires a company to establish a "reserve" for future income tax audit adjustments that may increase the Company's income tax liability and thus reduce the balance of ADITs recorded on its accounting books. Per FIN 48, a liability recognized as a result of applying this interpretation shall not be classified as a deferred tax liability unless it arose from a taxable temporary difference. FPL witness Ousdahl testified that FPL had included the deferred taxes associated with the temporary differences related to the FIN 48 liabilities in the Company's balance of ADITs rather than with long-term liabilities in rate base. She stated that this practice was consistent with the treatment of the deferred taxes and FIN 48 liabilities for FERC reporting.

Witness Kollen also contended that FPL had improperly diluted the low-cost capital provided by customer deposits and the cost-free capital provided by ADITs by allocating pro rata adjustments over these capital components. However, FPL witness Ousdahl stated that allocating pro rata adjustments over only investor sources of capital would result in an inappropriate double counting of the low cost customer deposits and cost-free deferred income tax capital structure components. To support the Company's position on the issue, witness

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[44] 26 USC §168(k) (2009)

[45] Accounting for Uncertainty in Income Taxes, Statement of Financial Accounting Standards No. 48, §18 (Financial Accounting Standards Board, 2006). Cross Reference: Unrecognized Tax Benefits, FASB ASC 740-10-45-12 (Paragraph 740-10-45-12 of the Financial Accounting Standards Board Accounting Standards Codification). The Codification is the single source of authoritative nongovernmental U.S. generally accepted accounting principles (US GAAP) effective for interim and annual periods ending after September 15, 2009.

Ousdahl cited to some of our previous orders and demonstrated the effects of the double counting.

We are concerned that the double counting of deferred income taxes might result in a violation of tax normalization rules. Per IRC§168(i)(9),[46] tax normalization requires any ratemaking adjustment with respect to a utility's deferred income tax reserves to be consistently applied with respect to rate base, depreciation expense, and income tax expense. Pursuant to IRC §168(f)(2),[47] the consequence of violating the normalization method of accounting is the loss of the ability to claim accelerated depreciation for income tax purposes. Such a normalization violation would result in the loss of the ability to use accelerated tax methods of depreciation. Consistent with prior PSC orders, tax normalization rules, and as discussed in greater detail below, FPL has properly allocated pro-rata adjustments to all sources of capital.

Based on the foregoing, we find that the methodology used by FPL to calculate ADITs is proper and is consistent with SFAS 109, FIN 48, and Internal Revenue Code covering the projected test year. After making adjustments, the appropriate amount of accumulated deferred taxes to include in FPL's capital structure is $2,892,247,084 for the projected 2010 test year. This amount represents the adjustments proposed by FPL in its testimony, which were incorporated along with our own adjustments to depreciation expense and accumulated depreciation.

Unamortized investment tax credits

In its initial filing, FPL recorded a balance of $56,983,000 of jurisdictional investment tax credits (ITCs) in the Company's capital structure for the projected 2010 test year. After its initial filing, the Company revised some of its specific adjustments to long-term debt and deferred income taxes, and accordingly adjusted the balance of ITCs. In its original filing, FPL removed solar plant amounts from rate base for clause recovery but did not remove solar-related ITCs from the capital structure. In a later filing, FPL corrected its error which resulted in a decrease to the balance of ITCs of $51,565,000 in 2010. The Company's revised MFR Schedule D-1a reflected a jurisdictional ITC balance of $5,426,000 for 2010. An additional adjustment was made as a result of rate base and cost of capital adjustments made by the Company related to the removal of aviation expenses.

FPL and OPC disagreed over the methodology for calculating the ITC cost rate. FPL's methodology for calculating the ITC cost rate was to apply the respective cost rates to the respective balances of common equity, preferred stock (none), and long-term debt. OPC's methodology for determining the ITC cost rate was to apply the respective cost rates to all of FPL's investor sources of capital, including short-term debt. We find that the investments that qualify for ITCs are those that are financed with long-term investor sources of capital. Accordingly, we find that FPL's methodology for calculating the balance of and cost rate for ITCs is appropriate and is in accordance with IRS requirements.

[46] 26 USC §168(i)(9) (2009)
[47] 26 USC §168(f)(2) (2009)

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While we agree that FPL's methodology for calculating the cost rate for ITCs is correct, we disagree with FPL's proposed cost rate. FPL proposed a 9.74 percent cost rate for 2010 based on the Company's proposed return on equity of 12.50 percent and long-term debt cost rate of 5.55 percent applied to the relative percentages of these sources of capital. OPC proposed a cost rate for ITCs of 7.41 percent for 2010. The OPC proposed cost rate was based on the return on equity and long-term debt cost rate recommended by OPC witness Woolridge. Accordingly, we recalculated the 2010 ITC cost rate based on the approved 10.00 percent ROE and the approved long-term debt cost rate of 5.49 percent. This resulted in a cost rate for ITC's of 8.19 percent. Based on the foregoing, the appropriate jurisdictional balance of unamortized ITCs to include in FPL's capital structure is $5,429,401 at a cost rate of 8.19 percent for the projected 2010 test year.

Cost rate for short-term debt

We heard testimony and received record evidence for a 2010 weighted average short-term debt cost rate ranging from .60 percent to 2.96 percent. FPL proposed a cost rate for short-term debt of 2.96 percent for 2010. OPC asserted that the appropriate short-term debt cost rate for 2010 was 2.27 percent. SFHHA supported a short-term debt cost rate of .60 percent which reflected the 3-month London Interbank Offered Rate (LIBOR) rate as of June 30, 2009.

FPL's proposed cost rate for short-term debt of 2.96 percent included both interest charges related to commercial paper borrowings based on the 30-day forward LIBOR curve as of November 30, 2008 and fixed costs related to maintaining back-up credit facilities to support FPL's commercial paper program. FPL witness Pimentel testified that it was appropriate to recover the $1,536,000 in annual commitment fees associated with FPL's use of short-term debt in the cost rate.

FPL's 2.96 percent cost rate for short-term debt was comprised of an assumed commercial paper borrowing rate of 2.12 percent, plus an allowance for commitment fees associated with accessing its credit facility of 0.84 percent. The following Table 19 shows FPL's 2008-2011 short-term debt balances, the annual credit facility commitment fees, fees as a percentage of short-term debt, short-term debt cost rates, and the total short-term debt cost rate.

Table 19

Year	(1) Short-term Debt Balance	(2) Annual Credit Facility Fees	(3) Annual Credit Facility Fee Percentage (2)/(1)	(4) Short-term Debt Cost Rate	(5) Total Short Term Debt Cost Rate (3)+(4)
2008	$353,370,000	$1,993,000	.56%	1.96%	2.52%
2009	$242,016,000	$1,536,000	.63%	1.64%	2.27%
2010	$181,615,000	$1,536,000	.84%	2.12%	2.96%
2011	$83,370,000	$1,536,000	1.84%	2.77%	4.61%

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As shown in Table 19 above, the annual credit facility fees were calculated as a percentage of the short-term debt balance.

Witness Pimentel testified that forward LIBOR curves best represent market expectations regarding future interest rates and thus it would not be appropriate to use historical rates or a rate from a specific point in time. In addition, witness Pimentel viewed the current low rates as a market anomaly, and did not expect this trend to continue.

OPC witness Woolridge asserted that the appropriate short-term debt cost rate for 2010 was 2.27 percent. Witness Woolridge testified that a 2009 short-term debt cost rate of 2.27 percent was more appropriate than the Company's proposed 2.96 percent for 2010. Witness Woolridge asserted that his recommended cost rate reflected current market interest rates and was not based on speculative forecasts of interest rates. Witness Woolridge testified that the LIBOR peaked in the third quarter of 2008 at 4.75 percent, and since then declined to below 1.0 percent as the short-term credit markets opened up and Treasury rates remained low. In addition, witness Woolridge proposed an increase in the relative balance of the short-term debt reflected in the capital structure to reflect the higher relative percentage of short-term debt maintained in the past.

SFHHA witness Baudino supported a short-term debt cost rate of .60 percent which reflected the 3-month LIBOR rate as of June 30, 2009. Additionally, SFHHA witness Kollen recommended that the annual facility and administrative fees for the Company's credit term loan facilities be included as an expense in the determination of the revenue requirement. Witness Baudino also supported an increase in the relative amount of the short-term debt as a percentage of the capital structure.

SFHHA's proposed short-term cost rate of .60 percent derived from the actual 3-month LIBOR as of June 30, 2009, is not an appropriate short-term cost rate since the cost rate should incorporate the annual credit facility fee charges. In addition, the SFHHA adjustment to include the facility and administrative fee associated with the Company's credit term loan facilities as an operating expense is not appropriate in this instance. These fees are a true cost of issuing short-term debt and shall be included in the cost of debt.

OPC's proposed short-term cost rate of 2.27 percent taken from FPL's MFR Schedule D-3 actual 2009 calculation is not appropriate in this instance. The use of OPC witness Woolridge's short-term cost rate overstates FPL's cost rate for 2010 since OPC's rate is historical and does not factor in more current projections. We also disagree with FPL's recommendation to use a dated 30-day forward LIBOR curve as of November 30, 2008. Instead of the November 30, 2008 LIBOR curve, the appropriate short-term cost rate shall be calculated utilizing an interpolated percentage of the more recent 30-day LIBOR curve projection as of July 28, 2009. In addition, an average of the annual credit facility fee percentages from 2008-2010 of .68 percent will sufficiently compensate the Company for these annual fees.

Accordingly, we find that the appropriate cost rate for short-term debt is 2.11 percent for the projected 2010 test year. We arrived at this cost rate by utilizing a methodology similar to that used by FPL and OPC but we relied on more current information from the hearing record to make our computation. We used an interpolated percentage of the 30-day forward LIBOR curve as of July 28, 2009, to obtain a more current projected interest rate of 1.43 percent for 2010. We added 68 basis points for the average cost of credit facility fees to the interpolated borrowing rate of 1.43 percent for a total short-term debt cost rate of 2.11 percent.

Cost rate for long-term debt

We received record evidence for a 2010 weighted average long-term debt cost rate ranging from 5.14 percent to 5.55 percent. Both OPC and FPL used the same methodology of calculating the long-term debt cost rate, but OPC witness Woolridge applied FPL's 2009 long-term debt cost rate of 5.14 percent to the 2010 projected test year. Witness Woolridge stated that the long-term debt cost rate should be based on current market interest rates, not based on speculative forecasts of interest rates.

FPL proposed a 5.55 percent cost rate for long-term debt for 2010. This proposed rate was based on the weighted average cost rate of the Company's existing debt and projected debt offerings in 2009 and 2010 based on the Blue Chip Financial Forecast (Blue Chip) consensus forecast of December 1, 2008. FPL's proposed cost rate for long-term debt took into account the actual cost of debt on all of the Company's billions of dollars of outstanding long-term debt as well as projected future costs of incremental long-term debt to be issued in the future, for which forecasted interest rates were considered.

FPL witness Pimentel explained that FPL's MFRs had been predicated on its expectation to issue $300 million of three year debt in January 2009 at an interest rate of 3.3 percent. However, the debt was not issued at that time and FPL instead issued $500 million of 30-year bonds at 5.96 percent in March 2009. Witness Pimentel stated that the additional funds raised would reduce the October and December 2009 projected issuances to keep the total amount of debt raised in 2009 issuance at $1 billion.

FPL witness Pimentel disagreed with OPC witness Woolridge's recommended cost rate for long-term debt of 5.14 percent. Witness Pimentel stated that he did not agree with witness Woolridge's use of the overall embedded long-term debt cost rate for 2009 as the long-term debt cost rate for 2010. Witness Pimentel argued that for the 2010 long-term debt cost rate to remain at the 2009 embedded cost rate of 5.14 percent, FPL would need to issue long-term debt in 2009 and 2010 at an average rate of 3.70 percent. Witness Pimentel stated that the Company's actual weighted average cost of long-term debt for 2009, excluding storm recovery bonds, was 5.43 percent.

FPL provided a revised MFR Schedule D-4a to correct some calculation errors and to update the schedule to reflect actual issuances that did not take place as projected due to market conditions. FPL witness Pimentel asserted that the actual debt that the Company issued in the first quarter of 2009 along with the updated interest rate projections from the June 2009 Blue Chip Financial forecast for projected debt issuances were considered together, it would result in a slightly higher interest rate than the rate proposed in FPL's original MFR Schedule D-4a.

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FPL maintained that it would be unreasonable and erroneous to adopt a lower long-term cost of debt for FPL in this proceeding based upon the more recent Blue Chip projections of interest rates - i.e. taking this one data point out of context - without also taking into account the updated facts testified to by witness Pimentel. We agree with FPL that updated information in the record should be incorporated in the revisions. Conversely, we disagree with FPL that it is inappropriate to use an updated forecast when determining the appropriate long-term cost rates as well as revising any errors in the original filing.

We calculated the long-term rate for 2010 based on updated information and updated revisions from the record before us. We determined that FPL made an error of including a nonexistent AAA- credit rating in its interpolation of the Company's A+ credit rating positioned between AAA and BBB. This error had the effect of overestimating the long-term cost of debt for FPL. In addition, we applied the more recent October 2009 Blue Chip forecast and the June 2009 Blue Chip forecast (Biannual edition) to update FPL's projected long-term coupon rates. Table 20 below shows FPL's originally proposed interest rates based on the December 2008 Blue Chip Financial forecast and our estimated rates based on FPL's methodology updated for forecasts from the June and October 2009 editions of Blue Chip, correcting for the interpolation error, and recognizing the other adjustments FPL made in its revised MFR Schedule D-4a.

Table 20

Estimated Coupon Rate Calculation	Blue Chip Financial Forecast Edition(s)	S&P Credit Rating	2009 Estimated Coupon Rate	2010 Estimated Coupon Rate
FPL	December 2008	A+	7.11%	6.88%
Commission	June & October 2009	A+	5.95%	6.29%

To calculate the appropriate embedded cost of long-term debt, we made adjustments to FPL's revised MFR Schedule D-4a for 2010. For the specific debt issuances projected by FPL, we substituted FPL's estimated coupon rates of 7.11 percent for 2009 and 6.88 percent for 2010 with the updated estimated coupon rates of 5.95 percent and 6.29 percent, respectively, based on updated interest forecasts from more current Blue Chip forecasts. In addition, the 3-year notes that were not actually issued in January 2009 and the storm securitization bonds have been removed from this calculation. The net effect of the above adjustments results in a six basis point decrease in the cost rate for long-term debt for 2010 from 5.55 percent to 5.49 percent. Based on the foregoing, the appropriate cost rate for long-term debt is 5.49 percent.

<u>Reconciliation of rate base and capital structure</u>

We next turned to the determination of whether adjustments made by FPL to rate base have been appropriately reconciled to the capital structure. In making this determination, we first determined whether certain specific adjustments were appropriately made. We then evaluated whether certain pro rata adjustments should be reconciled over all sources of capital or over investor sources of capital only. MFR Schedule D-1b listed the specific and pro rata adjustments that FPL made to the Company's proposed capital structure for the 2010 projected test year. FPL made specific adjustments to the balances of common equity, long-term debt, investment tax credits (ITCs), and accumulated deferred income taxes (ADITs). After FPL made specific adjustments to specific components in the capital structure, all other adjustments were made pro rata over all sources of capital.

FPL witness Ousdahl asserted that a significant portion of FPL's pro rata adjustments reflected the removal of clause-related plant and Allowance for Funds Used During Construction (AFUDC)-eligible CWIP from FPL's retail rate base. Witness Ousdahl testified that these rate base items were removed because they earned their own return outside of base rates. Additionally, witness Ousdahl stated that the clause items earned a Commission-approved rate of return that was calculated over all sources of capital, including ADITs, customer deposits, and ITCs. Moreover, witness Ousdahl stated that when these items are removed from rate base, it is appropriate to make the necessary reconciling adjustment to the capital structure on a pro rata basis over all sources of capital in order to avoid double-counting the benefit of zero cost deferred taxes and low cost customer deposits.

OPC argued that specific adjustments should be made to the balances of customer deposits, ADITs and ITCs based on corresponding rate base adjustments, and no further pro rata adjustments to these accounts should be made to reconcile the Company's capital structure to rate base. SFHHA also stated that the balances of customer deposits, ADITs and ITCs should not be reduced for pro rata adjustments to reconcile the Company's capitalization to rate base. SFHHA witness Kollen argued that FPL had improperly diluted the low-cost capital provided by customer deposits and the cost-free capital provided by ADITs by allocating pro rata adjustments over these capital components. Witness Kollen explained that capital amounts should be directly assigned to ratepayers in the same manner as if the amounts had been used to reduce rate base. Witness Kollen maintained that customer deposits and ADITs were not used to finance the amounts that comprised the total of FPL pro rata adjustments.

FPL argued that making the adjustment in the manner it proposed was the easiest way to avoid a potential violation of the Internal Revenue Service (IRS) tax normalization rules and avoid the risk of losing the IRS tax benefit of accelerated depreciation. FPL witness Ousdahl explained that reconciling rate base over all sources of capital also matched the way FPL expended cash in the normal course of its operations. FPL funds its operations from a pool of funds that is generated from all sources of capital - including deferred taxes, customer deposits and investment tax credits.

In support of its position, FPL cited our treatment of Tampa Electric Company's (TECO) method of reconciling adjustments approved in Order No. PSC-09-0571-FOF-EI.[48] However, in that order we identified seven additional orders in which the incremental adjustment to rate base was made through pro rata adjustments over investor sources of capital only.[49] In addition, we

[48] Order No. PSC-09-0571-FOF-EI, issued August 21, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

[49] Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 080366-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PSC-08-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In re: Petition for rate increase by St. Joe Natural Gas Company, Inc.; Order No. PSC-04-1110-PAA-GU, issued November 8, 2004, in Docket No. 040216-GU, In re: Application for rate increase by Florida Public

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stated in Order No. PSC-09-0571-FOF-EI, "Our decision on this point is specific to the record in this case and shall not be considered precedent regarding our position on this or similar issues in future proceedings." That said, FPL did not furnish the information we requested concerning adjustments by plant to the balances of ADITs and ITCs. The following passage is the response by FPL to a discovery request to identify the balances of ADITs and ITCs by plant:

> For the forecast period, the Company did not specifically identify accumulated deferred income taxes or investment tax credits by plant. The Company forecasts the temporary differences for each annual period and identifies the change in deferred income taxes applicable to those temporary differences for each period. The temporary differences during the forecast period are not specifically identified to a specific plant. The amounts are provided in the aggregate in the determination of the taxable income and the accumulated deferred income taxes applicable to a specific plant item have not been separated by temporary differences in the accumulated deferred taxes balance. To determine the deferred income taxes related to CWIP for a specific item, a close out schedule for temporary differences would be required to reflect the transfer of temporary difference from CWIP to plant in service and the related allocation of book depreciation to the various forecasted basis (temporary) differences. For the test year 2010 and the subsequent year, 2011, the amount of deferred tax liabilities forecasted to be generated relating to CWIP were approximately $176 million and $143 million, respectively. During these same periods, deferred income tax liabilities related to plant in service decreased for 2010 by $17 million and increased by $4 million for 2011. Related to the investment tax credits, the Company calculated the estimated amount of investment tax credits to be generated from solar and reported the amounts in the applicable year; it also provided for the amortization beginning on the estimated in-service date. The amortization of investment tax credits is not tracked by plant and is combined by rate on the balance sheet.

We agree with SFHHA witness Kollen that it has been our practice to make specific adjustments where possible and to prorate other rate base adjustments over investor sources only.[50] If an adjustment does not involve plant, then it is likely that the account in question did not produce deferred taxes or ITCs. Absent a showing that specifically identifies ADITs and ITCs associated with a non-plant related adjustment, all adjustments for amounts unrelated to plant shall continue to be removed from the capital structure through a pro rata adjustment over investor sources of capital only.

Utilities Company; Order No. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 030569-GU, In re: Application for rate increase by City Gas Company of Florida; Order No. PSC-01-1274-PAA-GU, issued June 8, 2001, in Docket No. 001447-GU, In re: Request for rate increase by St. Joe Natural Gas Company, Inc.; and Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, in Docket No. 000768-GU, In re: Request for rate increase by City Gas Company of Florida.

[50] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PSC-08-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In re: Petition for rate increase by St. Joe Natural Gas Company, Inc.

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FPL did not follow our practice in this rate case; however, we will permit FPL to make the pro rata adjustments as it proposed. In this particular instance, there are three reasons why we are permitting FPL to make pro rata adjustments over all sources of capital. First, FPL has made a compelling argument regarding the plant items that earn an AFUDC rate and clause items that earn a Commission-approved rate of return. The AFUDC return is calculated over all sources of capital, including deferred taxes, customer deposits, and investment tax credits. When these items are removed from rate base, it is appropriate to make the necessary reconciling adjustment to the capital structure on a pro rata basis over all sources of capital to avoid double-counting the benefit of zero cost deferred taxes and low cost customer deposits. Second, FPL asserted that to avoid a potential violation of IRS tax normalization rules,[51] the rate of return for clause-related plant and AFUDC-eligible CWIP removed from the rate base should be calculated using the same methodology as the rate of return for the jurisdictional rate base so that adjustments to ADITs are applied consistently. We are concerned about the potential loss of deferred income tax treatment by violation of IRS tax normalization rules. Third, as shown below in Table 21, we have calculated the relative difference in the overall cost of capital resulting from the two methodologies of reconciling rate base and capital structure. This difference does not justify the negative consequence of a normalization violation.

Table 21

	Pro rata adjustment over all sources of capital	Pro rata adjustment over investor sources only	Difference
2010 Weighted Average Cost of Capital	7.00%	6.92%	8 basis points

Overall, we are concerned about symmetry in the treatment of reconciling rate base and capital structure. But the proper venue (to address the appropriate methodology for reconciling

[51] As defined in Order No. PSC-09-0571-FOF-EI, issued August 21, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Normalization requirements are outlined in Section 168 of the Internal Revenue Code (IRC). In pertinent part, Section 168 permits the use of accelerated depreciation methods. However, accelerated depreciation is permitted with respect to public utility property only if the taxpayer uses a normalization method of accounting for ratemaking purposes. Under a normalization method of accounting, a utility calculates its ratemaking tax expense using depreciation that is no more accelerated than its ratemaking depreciation (typically straight-line). In the early years of an asset's life, this results in ratemaking tax expense that is greater than actual tax expense. The difference between the ratemaking tax expense and the actual tax expense is added to a reserve (the accumulated deferred income tax reserve, or ADIT). The difference between ratemaking tax expense and actual tax expense is not permanent and reverses in the later years of the asset's life when the ratemaking depreciation method provides larger depreciation deductions and lower tax expense than the accelerated method used in computing actual tax expense. This accounting treatment prevents the immediate flowthrough to utility ratepayers of the reduction in current taxes resulting from the use of accelerated depreciation. Instead, the reduction is treated as a deferred tax expense that is collected from current ratepayers through utility rates, and thus is available to utilities as cost-free investment capital. When the accelerated method provides lower depreciation deductions in later years, only the ratemaking tax expense is collected from ratepayers and the difference between the actual tax expense and ratemaking tax expense is charged to ADIT, depleting the utility's stock of cost-free capital. (http://edocket.access.gpo.gov/2003/03-4885.htm)

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the capital structure to rate base) is a generic docket to address the issue, since it would affect all IOUs, not just FPL. The appropriate method to reconcile rate base to capital structure is to make adjustments to the class of capital in the capital structure that correspond to the adjustments made to related accounts in rate base. For example, adjustments made to rate base from accounts that do not generate deferred taxes or investment tax credits should not be reconciled over deferred taxes or investment tax credits in the capital structure. Accordingly, we will open a generic docket to address this issue on a prospective basis.

In this docket, FPL did not provide the information necessary to itemize specific adjustments to the balances of ADITs and ITCs for the amounts removed from rate base. The record shows that FPL did not specifically identify its sources of capital and trace its funding usage. The omission of information should not inure to the benefit of the party responsible for providing that information. However, we find that the risk of losing the benefit on accumulated deferred income taxes in the determination of customer rates due to a tax normalization violation outweighs our concern in this instant case. Based upon the foregoing, after making certain specific adjustments, we find that for the sole purpose of setting rates in this rate case only, rate base and capital structure have been reconciled appropriately.

Equity ratio

The goal of an appropriate equity ratio and capital structure is to minimize the overall weighted average cost of capital and to maintain consistent access to capital under reasonable terms. This is an important consideration in that it is the overall cost of capital that is used to determine revenue requirements and ultimately customer rates.

To reach our decision of the appropriate equity ratio and capital structure, we start with a review of whether FPL has appropriately described the actual 59.6 percent equity ratio that it proposed to use for ratemaking purposes as an "adjusted 55.8 percent equity ratio" on the basis of imputed debt associated with FPL's purchased power contracts. This question involves the different ways FPL's test year equity ratio has been presented for purposes of this proceeding.

A company's capitalization can be expressed in a number of ways. For purposes of financial reporting, a company will report its capitalization in accordance with Generally Accepted Accounting Principles, often referred to as on a "GAAP" basis. GAAP prescribes specific requirements for how a company's book capital structure will be presented. Another way a company's capitalization ratios can be expressed is from the perspective of the rating agencies. For their own analytical purposes, rating agencies often make adjustments to a company's capitalization ratios to include certain items that are not recorded on the balance sheet and to remove other items that are recorded on the balance sheet pursuant to GAAP. A third way of expressing a company's capitalization, if the company in question is a regulated utility, is on a Commission-adjusted basis. These adjustments are made to capital structure and rate base primarily to account for the removal of rate base items that are recovered outside of base rates.

Due to differences between GAAP requirements, rating agency adjustments, and regulatory requirements, it is common for a company's reported equity ratio to vary. The table below shows FPL's projected 2010 test year equity ratio as a percentage of investor capital expressed on a GAAP, Standard & Poors' (S&P), and Commission (PSC) basis.

Table 22

	GAAP	S&P	PSC
Equity Ratio	55.6%	55.8%	59.6%

Annual reports for shareholders as well as filings made with the Securities and Exchange Commission (SEC) are prepared in accordance with GAAP. On a GAAP basis, FPL's capitalization will include the storm recovery bonds issued in 2007 to finance storm restoration costs and replenish the storm reserve.[52] The annual reports and filings with the SEC will not, however, reflect imputed debt associated with FPL's purchased power agreements in the balance sheet and income statement. The capitalization ratios reflected in the GAAP statements are expressed on a year end basis.

S&P routinely makes adjustments to the financial statements of companies for purposes of its own analytical review. S&P will make an adjustment to FPL's capitalization to remove the storm recovery bonds because these bonds are non-recourse to the Company. S&P will also impute debt in FPL's capitalization ratios to reflect the fixed payment obligation associated with FPL's purchased power agreements. These "adjusted" financial statements are also on an annual basis.

From a regulatory perspective, we require certain adjustments that also impact FPL's capitalization ratios. For purposes of this proceeding, FPL made adjustments to long-term debt to remove the storm recovery bonds that are recovered through a separate line charge and to remove nuclear fuel capital leases that are recovered through the fuel cost recovery clause. With the exception of the adjustment recognized pursuant to the 2005 Stipulation negotiated between the parties to settle PEF's 2005 rate case approved in Order No. PSC-05-0945-S-EI,[53] base rate-related filings with us do not reflect imputed debt associated with purchased power agreements. For ratemaking purposes, FPL's financial statements are expressed on a 13-month average basis.

As demonstrated above, FPL was technically correct from a GAAP and S&P basis when it described its proposed equity ratio for purposes of this proceeding as approximately 55 percent. However, we do not set rates for FPL based on its GAAP or S&P adjusted equity ratios. We determine FPL's overall cost of capital, and therefore its revenue requirements, based on FPL's regulatory adjusted equity ratio. Accordingly, while the Company's GAAP and S&P equity ratios may be expressed as 55.6 and 55.8 percent, respectively, the equity ratio reflected in FPL's original MFR filing for purposes of determining revenue requirements in this proceeding is appropriately described as 59.6 percent.

[52] Order Nos. PSC-06-0464-FOF-EI, issued May 30, 2006, and PSC-06-0626-FOF-EI, issued July 21, 2006, collectively known as the Financing Order, in Docket No. 060038-EI, In re: Petition for issuance of a storm recovery financing order, by Florida Power & Light Company.
[53] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc., (2005 Stipulation).

Having determined that FPL has appropriately described its equity for purposes of this proceeding, we next address what is the appropriate equity ratio that we will use for ratemaking purposes in this case. All witnesses that testified on this issue were in agreement that we should approve a rate of return for FPL that maintains its financial integrity and allows the Company continued access to the capital markets under reasonable terms. The disagreement between the witnesses concerned the relative magnitude of the equity ratio recognized for purposes of determining revenue requirements that is necessary to achieve these results. FPL proposed that for purposes of setting its revenue requirements, we recognize its equity ratio as a percent of investor capital of 59.6 percent. OPC recommended that we adopt an equity ratio of 54.4 percent. FIPUG suggested the equity ratio be reduced to 50.2 percent and SFHHA recommended an equity level of 53.5 percent.

FPL witness Pimentel testified that it is critical for FPL to maintain its financial strength as it confronts the challenges of meeting significant infrastructure investment requirements during this period of financial uncertainty as the nation comes out of the global economic recession. He noted that FPL's strong balance sheet has provided continuous access to both short-term liquidity and long-term capital throughout extreme events such as the 2004 and 2005 storm seasons, the spike in natural gas prices, and the disruption in the financial markets in the fall of 2008. Witness Pimentel testified that FPL's current equity ratio provides for the liquidity requirements and financial flexibility necessary to be in a position to fund future storm restoration activities, hedge fuel price volatility, and fund substantial infrastructure investment.

FPL witness Avera acknowledged that FPL's requested equity ratio is at the upper end of the range of equity ratios for both the companies in his proxy group as well as the investor-owned utilities (IOUs) they own. However, he testified that it is appropriate for FPL to maintain this level of equity given the risks and challenges that the Company faces. Witness Pimentel testified that FPL has consistently maintained this relative equity position, on an adjusted basis, since the we approved the 1999 Revenue Sharing Agreement in Order No. PSC-99-0519-AS-EI.[54] He also noted that FPL's "adjusted" equity ratio of 55.8 percent has been and continues to be viewed as adequate and appropriate by the investment community.

In evaluating the adequacy of the capital structure of a company, witness Pimentel testified that rating agencies will take into account major financial commitments that are not reflected on the balance sheet such as long-term purchased power agreements. FPL witness Avera testified that FPL must be mindful of how the investment community views the Company's capital structure. He also stressed that, unlike TECO[55] and PEF,[56] FPL is not requesting that imputed equity be included in its regulatory capital structure. Because rating agencies and the investment community consider the impact of such fixed obligations when assessing the Company's financial position, both witnesses Pimentel and Avera testified that we

[54] Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI, In re: Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company, (1999 Agreement).
[55] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, pages 36–42.
[56] Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., staff recommendation filed November 30, 2009, pages 146–149.

should consider these obligations when evaluating the reasonableness of FPL's proposed equity ratio.

OPC witness Woolridge testified that the 59.6 percent equity ratio as a percentage of investor capital reflected in the Company's filing "is well in excess of the common equity ratios of electric utility companies." He noted that there is a direct correlation between the relative amount of equity in the capital structure and the revenue requirements the customers are called upon to bear. Witness Woolridge testified that if the proportion of equity is too high, rates will be higher than they need to be. For this reason, he recommended that FPL pursue a capitalization strategy that strikes a more appropriate balance of equity and debt in the capital structure.

OPC recognized that FPL is not proposing to impute equity in its capital structure for purposes of setting rates in this proceeding, but stressed that the "actual adjusted" equity ratio of 55.8 percent is not the equity ratio that the Company has employed to calculate its revenue requirements. Because FPL's proposed capital structure ratios do not reflect the actual capitalization of FPL or FPL Group, Inc. (FPL Group) and because the proposed equity ratio is much higher than the equity ratios of other electric utilities, witness Woolridge recommended we recognize a lower equity ratio for ratemaking purposes.

Witness Woolridge recommended an equity ratio of 54.4 percent as a percentage of investor capital. This equity ratio was based on the average of FPL's projected year end capitalization ratios for 2009 and 2010. Because these year end balances differ from the 13-month average balances reported on MFR Schedule D-1a, accomplishment of witness Woolridge's recommended equity ratio would entail adjustments that decrease the relative amount of common equity and increase the relative amounts of long-term and short-term debt. Because his recommended capital structure was based on Company book figures, witness Woolridge testified that his equity ratio more accurately reflected the Company's equity ratio as viewed by investors.

FIPUG witness Pollock challenged the testimony of FPL witnesses that it is necessary for us to consider the impact of imputed debt associated with purchased power agreements. He noted that, due to our approval of purchased power agreements and the full and direct recovery of firm energy and purchased power capacity payments through the fuel and capacity cost recovery clauses, there is minimal recovery risk associated with purchased power agreements in Florida. Thus, consideration of imputed debt is unnecessary in assessing the reasonableness of FPL's capital structure. Witness Pollock testified that, at an equity ratio approaching 60 percent, FPL would be one of the least leveraged regulated electric utilities in the nation.

Witness Pollock recommended an equity ratio of 50.2 percent as a percentage of investor capital. This equity ratio was based on the average equity ratio for single A-rated electric utilities followed by SNL Financial for the period 2006 through the first quarter of 2009. Because FPL is rated single A1 by Moody's Investors Service (Moody's) and single A flat by both Fitch Ratings (Fitch) and S&P, he recommended that the Company's equity ratio should be adjusted to be more comparable to the average equity ratio of other comparably-rated electric utilities.

SFHHA witness Baudino recommended that FPL's equity level be reduced to 50.0 percent on an adjusted basis to conform with the high end of S&P's debt-to-total capital range consistent with a single A rating. He stated that his recommended adjusted equity ratio equates to a ratemaking equity ratio of 53.5 percent. He suggested that this adjustment be accomplished, in part, through an increase in the balance of short-term debt of $600 million to be consistent with the Company's short-term debt levels over the last few years. Witness Baudino concluded that his proposed capital structure strikes an appropriate balance between the interests of Company shareholders and customers, results in an equity ratio consistent with a single A rating, and is supportive of FPL's credit quality.

Witness Baudino testified that approval of an "excessive" equity ratio for FPL could result in customers subsidizing FPL Group's unregulated affiliate operations. S&P employs a consolidated rating methodology whereby it generally assigns a rating to each entity in an organization based upon the credit profile of the consolidated entity. Witness Baudino argued that FPL Group could not maintain a single A rating on a consolidated basis without the support of an excessive FPL equity ratio. He noted the higher debt leverage maintained at the funding vehicle for FPL Group's unregulated operations (FPL Group Capital) and by FPL Group on a consolidated basis relative to the debt leverage maintained at FPL. He also referred to a February 12, 2009 report on FPL wherein S&P cautioned that FPL's rating could be pressured if FPL Group failed to manage significant risks in its merchant energy and energy marketing and trading operations. Because the level of equity for ratemaking purposes should reflect the risk associated with regulated operations, not to offset higher debt leverage at the consolidated level, witness Baudino recommended that the Company's equity ratio be reduced.

Since the approval of the 1999 Agreement, FPL has consistently maintained the proposed relative level of equity capitalization. For the period 1999 through 2008, FPL earned approximately $8.0 billion in net income. Over this period, approximately $4.1 billion was retained by FPL Group and $3.9 billion was invested in FPL in order to maintain the relative balance of debt and equity in its capital structure that it has proposed be recognized for purposes of this proceeding.

Unlike the filings by TECO and PEF, FPL is not requesting any adjustment to its regulatory capital structure to offset the impact of imputed debt associated with purchased power agreements. The Company witnesses have testified that, from the rating agencies' perspective, purchased power agreements represent a debt-like obligation that we should consider when evaluating the reasonableness of the capital structure maintained by FPL. In addition to the impact purchased power agreements have on the Company's financial flexibility, witness Pimentel also urged us to consider the challenges faced by FPL when determining the appropriate capital structure. These challenges include having the financial strength and flexibility to fund potentially significant storm restoration efforts, to hedge fuel price volatility, and to maintain the ability to raise capital under reasonable terms even during periods of economic uncertainty and market volatility.

SFHHA witness Baudino raised the concern that if an "excessive" equity ratio is approved for FPL, it could result in inappropriate cross subsidization through the cost of capital. We take concerns regarding cross subsidization between regulated and unregulated operations of a consolidated entity very seriously. As in all cases that come before us, we are prohibited from setting rates to make up for losses or inadequate returns of affiliated companies. FPL witness Pimentel explained that intervenor witnesses made inappropriate comparisons between FPL's equity ratio and the equity ratio supporting FPL Group's unregulated operations. After considering rating agency adjustments for non-recourse project debt and hybrid capital instruments supporting the unregulated operations, debt leverage at FPL Group Capital and FPL Group on a consolidated basis, while still higher than for FPL, is not as pronounced as a comparison of their respective book capitalizations might suggest. Moreover, to the extent we approve an equity ratio for FPL that represents the high end of the range of ratios for other, comparably situated electric utilities, this lower financial risk position is recognized with our setting of FPL's authorized return on equity (ROE) in this proceeding.

FPL's position of financial strength has served it and its customers by holding down the Company's cost of capital. During the recent volatility in the capital markets, many companies experienced sharp spikes in their cost to borrow. In some instances, companies had to accept rates as high as 10 percent to issue bonds. In the case of FPL, however, due to its strong financial position it was able to sell 30-year bonds at rates under 6 percent during 2008 and 2009 despite the significant disruption in the credit markets.

In its original filing, FPL requested an overall cost of capital of 8.00 percent for 2010. FPL lowered its requested overall cost of capital to 7.85 percent for 2010 principally due to the recognition of additional zero cost accumulated deferred income taxes in the capital structure. The net impact of the net increase in the balance of accumulated deferred income taxes and decrease in the balance of investment tax credits discussed earlier in this order lowered FPL's Commission-adjusted equity ratio as a percentage of investor capital from 59.6 percent to 59.1 percent for 2010.

Based on the foregoing, we approve the capital structure shown on Schedule 2, attached to this order. This capital structure reflects an equity ratio as a percentage of investor capital of 59.1 percent for 2010. While this relative level of equity is near the top of the range of equity ratios of the IOUs owned by the companies in witness Avera's proxy group, it is still within the range of equity ratios of comparably rated IOUs. In addition, this equity ratio is consistent with the relative level of equity FPL has maintained, on an adjusted basis, over the past decade.

Capital Structure for purposes of setting rates

FPL proposed specific adjustments to long-term debt, common equity, and deferred income taxes in its original capital structure as shown in MFR Schedule D-1a. FPL made a specific downward adjustment to the balance of long-term debt in the amount of ($907,863,000). This amount of ($907,863,000) was comprised of ($374,898,000) in nuclear fuel capital leases, ($1,110,000) for prepayment interest on commercial paper, and ($531,855,000) for storm bonds. FPL witness Ousdahl explained that FPL Fuels, Inc. was established for the purpose of financing the acquisition of nuclear fuel and then subsequently leasing the fuel to FPL. However, the rating agencies no longer give off-balance sheet treatment to commercial paper issued by FPL Fuels, Inc. and changes in accounting rules now require FPL to consolidate FPL Fuels, Inc. into its financial statements, so there is no longer any benefit to maintain a separate fuel company.

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Therefore, for the reasons above FPL intended to dissolve FPL Fuels, Inc. on or before January 1, 2010.

FPL proposed a specific net downward adjustment to deferred taxes in the amount of ($259,006,000) comprised of ($332,507,000) for storm deficiency recovery and $73,501,000 for accumulated provision for property and storm insurance. Additionally, FPL proposed making a specific downward adjustment to remove nonutility property from common equity in the amount of ($9,519,000).

Subsequent to its original filing, the Company revised its specific adjustments to long-term debt and deferred income taxes, and proposed a new adjustment to investment tax credits as we discussed regarding unamortized tax credits. FPL's proposed adjustment to remove solar plant amounts from base rates for clause recovery did not include the removal of the related investment tax credits from the capital structure. Correction of this error resulted in a decrease to the balance of investment tax credits in the amount of $51,565,000 in 2010. In addition, a proposed adjustment to reflect the impact of the Stimulus Bill that were not known at the time of the original filing resulted in an increase in the balance of accumulated deferred income taxes in the amount of $288,261,000 in 2010. Finally, FPL inadvertently excluded the impact to accumulated deferred income taxes resulting from the company adjustment to include the impact of the change in depreciation rates specified by its depreciation filing. Correction of this error resulted in a decrease in the balance of accumulated deferred income taxes in the amounts of $16,508,000 in 2010.

We approve the Company's the proposed specific adjustments to long-term debt, common equity, deferred income taxes, and investment tax credits as detailed on Schedule 2. Accordingly, we find that the appropriate capital structure for the purpose of setting rates in this proceeding is based on FPL's projected 2010 capital structure with certain adjustments as discussed above. The appropriate capital structure for 2010 is shown on Schedules 2.

Return on equity

We were presented testimony and evidence supporting a range of return on equity (ROE) from 7.6 percent to 13.9 percent. Four witnesses testified in this proceeding regarding the appropriate ROE for FPL. FPL witness Avera testified that a reasonable ROE for FPL is in the range of 12.0 percent to 13.0 percent. FPL witness Pimentel, while not conducting his own independent analysis of the appropriate ROE for FPL, recommended the midpoint of witness Avera's recommended range, or 12.5 percent, as the appropriate ROE for FPL for purposes of this proceeding. OPC witness Woolridge recommended an ROE of 9.5 percent. SFHHA witness Baudino recommended an ROE of 10.4 percent. As expressly stated in the 2005 Settlement, FPL does not currently have an authorized ROE.[57] However, for purposes other than reporting or assessing earnings (such as cost recovery clauses and AFUDC), the 2005 Settlement Order provided for FPL to use an ROE of 11.75 percent.

[57] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, p. 3, (2005 Settlement).

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The statutory principles for determining the appropriate rate of return for a regulated utility are set forth by the U.S. Supreme Court in its Hope and Bluefield decisions.[58] These decisions define the fair and reasonable standards for determining rate of return for regulated enterprises. Namely, these decisions hold that the authorized return for a public utility should be commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms.

While the logic of the legal and economic concepts of a fair rate of return are fairly straightforward, the actual implementation of these concepts is controversial. Unlike the cost rate on debt that is fixed and known due to its contractual terms, the cost of equity is a forward-looking concept and must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the Hope and Bluefield decisions.

Three witnesses used the DCF model to estimate the investor-required ROE for FPL. Because FPL is a wholly-owned subsidiary of FPL Group, Inc. (FPL Group), its common stock is not publicly traded. To apply the model, each witness had to select a group of companies with publicly traded stock to serve as a proxy for FPL.

FPL witness Avera applied the DCF model to two proxy groups he determined to be comparable in risk to FPL. To select his first group of companies, witness Avera started with all electric utilities followed by Value Line Investment Survey (Value Line). From this initial sample, he eliminated all companies that did not have at least a triple B plus corporate credit rating from Standard & Poors' (S&P), a Value Line safety rank of 1 or 2, a Value Line financial strength rating of B++ or better, and at least two published earnings per share (EPS) growth projections from Value Line, Thomson I/B/E/S (IBES), First Call Corporation (First Call), and Zacks Investment Research (Zacks). Based on these selection criteria, witness Avera identified a proxy group of 19 utility companies (the Utility Proxy Group) that he testified reflect the risks and prospects associated with FPL's jurisdictional utility operations. To select his second proxy group, witness Avera started with all companies followed by Value Line. From this sample, he eliminated all companies that did not pay a dividend, had a Value Line safety rank less than 1, had a financial strength rating less than A, did not have an investment grade credit rating from S&P, and that did not have at least two published EPS growth projections from Value Line, IBES, First Call, and Zacks. Based on these selection criteria, witness Avera identified a proxy group of 66 non-utility companies (the Non-Utility Proxy Group). Considering the various measures of business and financial risk for the two proxy groups, witness Avera concluded that investors would likely view the overall investment risk of FPL to be comparable to the investment risks of the companies in both proxy groups.

[58] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Witness Avera used the constant growth DCF model to estimate the cost of equity for FPL. He derived the expected dividend yields from information published in December 2008 editions of Value Line. The dividend yields for the companies in the Utility Proxy Group ranged from 2.8 percent to 6.4 percent and averaged 6.0 percent for the group. The dividend yields for the companies in the Non-Utility Proxy Group ranged from 0.55 percent to 13.60 percent and averaged 3.52 percent for the group. He relied on security analyst EPS growth projections from Value Line, IBES, First Call, and Zacks as of January 2009 and the expected growth rate as measured by the sustainable growth approach to estimate the growth rate used in his DCF analysis. The growth rates for the companies in the Utility Proxy Group ranged from 0.0 percent to 12.0 percent. The growth rates for the companies in the Non-Utility Proxy Group ranged from (1.2) percent to 18.9 percent. The average of the growth rates used in his DCF analyses were 6.3 percent for the Utility Proxy Group and 10.1 percent for the Non-Utility Proxy Group. In evaluating the results of his DCF analyses, he determined it was appropriate to eliminate cost of equity estimates that were determined to be "extreme outliers." After eliminating "illogical low- and high-end values," the average results of witness Avera's DCF analysis applied to the Utility Proxy Group ranged from 10.6 percent to 11.5 percent. After applying the DCF model to the Non-Utility Proxy Group in the same manner, the average indicated returns ranged from 12.9 percent to 13.4 percent.

To select his group of comparable companies, OPC witness Woolridge started with all electric and combination electric and gas utilities followed by Value Line and AUS Utility Reports (AUS). From this initial sample, he removed all companies that did not have an investment grade bond rating from Moody's Investors Service (Moody's) and/or S&P, and a three year history of paying dividends. He further narrowed his proxy group by focusing on companies with annual operating revenues of at least $5 billion and that generate at least 70 percent of their operating revenues from regulated electric operations. Based on these selection criteria, witness Woolridge identified a group of 10 comparable companies for use in his analysis.

Witness Woolridge used the constant growth DCF model. He relied on dividend yields for the six month period ended July 2009 and for the month of July 2009 as reported by AUS Utility Reports. The expected dividend yield used in his analysis was 4.83 percent. He relied on Value Line's historical and projected growth rate estimates for EPS, dividends per share (DPS), and book value per share (BVPS). In addition, he used the average EPS growth rate forecasts from First Call, Zacks, and Reuters and the expected growth rate as measured by the earnings retention method. The average growth rate used in his analysis was 5.50 percent. The indicated return from witness Woolridge's DCF analysis was 10.33 percent.

To select his group of comparable companies, SFHHA witness Baudino started with all electric companies followed by AUS with at least a single A rating from Moody's and S&P. From this initial sample, he selected companies that generated at least 50 percent of their revenues from regulated electric operations and that had EPS growth forecasts from Value Line and either Zacks or First Call. He further narrowed his proxy group by removing all companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations. Based on these selection criteria, witness Baudino identified a group of 14 companies that he believed had a risk profile that is reasonably similar to FPL.

Witness Baudino used the constant growth DCF model. He derived the dividend yields used in his analysis based on information for the six month period ended June 2009 as reported by Yahoo! Finance. The monthly average dividend yields for the group ranged from 4.75 percent to 5.66 percent. The average expected dividend yield used in his analysis was 5.45 percent. He relied on Value Line projected EPS and DPS growth rate estimates. In addition, he used EPS growth rate forecasts from Zacks and First Call. Witness Baudino ran his DCF model under three slightly different growth rate assumptions. In method 1, he calculated the average of all growth rates from Value Line, Zacks, and First Call. In method 2, he calculated the median growth rate for his proxy group. In method 3, he omitted double digit growth rates and growth rates that were less than 1 percent from the calculation of the averages. The expected growth rates produced by all three methods fell in the range of 3.75 percent to 6.25 percent. Method 1 produced an indicated cost of equity range of 9.72 percent to 11.64 percent with an average of 11.01 percent and a midpoint of 10.68 percent. Method 2 produced an indicated cost of equity range of 9.10 percent to 11.66 percent with an average of 10.80 percent and a midpoint of 10.38 percent. Method 3 produced an indicated cost of equity range of 10.49 percent to 11.43 percent with an average of 11.13 percent and a midpoint of 10.96 percent. Based on this analysis, witness Baudino testified that his DCF analysis indicated a range of returns of 10.38 percent to 11.13 percent and he recommended we adopt an ROE of 10.40 percent for FPL.

All three witnesses used the same constant growth version of the DCF model. And with the exception of witness Avera's Non-Utility Proxy Group, all three witnesses used relatively similar estimates of dividend yields. The primary reason for the difference in the indicated DCF returns is attributed to differences in their respective estimates of the growth rate to include in the DCF model.

Both witnesses Woolridge and Baudino testified that the results of witness Avera's DCF analysis based on the Non-Utility Proxy Group is not appropriate to estimate the ROE for the regulated operations of FPL. Witness Woolridge testified that, because the companies in the Non-Utility Proxy Group are large and successful, have lines of business vastly different from the electric utility business, and do not operate in a highly regulated environment, "the non-utility group is not an appropriate proxy for FPL, and therefore the equity cost rate results for this group should be ignored." Witness Baudino testified that non-utility companies have higher overall risk structures than a low-risk electric utility like FPL and will have higher required returns from their shareholders. Given the greater degree of business risk for the non-utility companies, he stated that it should be expected that witness Avera's DCF results for his Non-Utility Proxy Group would be substantially higher than the results for his Utility Proxy Group. Witness Baudino concluded that "using higher required returns from a group of unregulated companies is obviously unjustified, inflates FPL's required ROE, and should be rejected by the Commission."

Witness Avera countered that his Non-Utility Proxy Group was screened to have corresponding risk indicators with FPL and is comprised of 66 of the best known and most stable corporations in America. He stated that the Hope and Bluefield decisions dictate that the

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allowed return be consistent with returns on investments of comparable risk but that neither decision restricted consideration to only utilities. Because utilities compete with unregulated companies for capital and his Utility and Non-Utility Proxy Groups are comparable in risk, witness Avera argued our consideration of the results of both DCF analyses is consistent with the regulatory standard established by Hope and Bluefield.

Three witnesses also performed a CAPM analysis. For the reason discussed earlier, the witnesses used their respective proxy groups for certain inputs to their CAPM analysis.

FPL witness Avera performed an ex ante, or forward-looking, CAPM analysis. For the estimate of the risk-free rate, he used the average yield on 20-year Treasury bonds for December 2008 of 3.2 percent. For the estimate of the company-specific risk, or beta, he used the average beta for his two proxy groups. The average beta for the Utility Proxy Group was .73 and the average beta for the Non-Utility Proxy Group was .84. Witness Avera relied on Value Line for his estimates of beta. He derived a market risk premium of 10.0 percent based on a DCF analysis of the dividend paying companies in the S&P 500. Witness Avera's CAPM analyses indicated returns of 10.5 percent for the Utility Proxy Group and 11.5 percent for the Non-Utility Proxy Group.

OPC witness Woolridge also performed an ex ante CAPM analysis. For the risk-free rate, he used an estimate of the forward-looking yield on 30-year U.S. Treasury bonds of 4.50 percent. For beta, he used the average Value Line beta for his group of proxy companies of .70. He determined an expected risk premium of 4.36 percent based on the results of various studies of historical risk premium, ex ante risk premium studies, and equity risk premium surveys. Witness Woolridge's CAPM analysis indicated an ROE of 7.6 percent.

SFHHA witness Baudino performed both an ex ante and an ex post, or historical, CAPM analysis. For the estimate of the risk-free rate, he used both the average yield on 5-year Treasury notes and 20-year Treasury bonds for the 6 months ended June 2009 of 2.00 percent and 3.94 percent, respectively. For the estimate of beta, he used the average beta for his proxy group of .69 as reported by Value Line. Witness Baudino derived a market risk premium range of 6.47 percent (based on the yield on 20-year Treasury bonds) to 8.41 percent (based on the yield on 5-year Treasury notes) for purposes of his ex ante CAPM. For purposes of his ex post CAPM, he relied on historical, earned returns from Ibbotson Associates to determine a market risk premium range of 4.40 percent to 5.97 percent. Witness Baudino's analysis indicated a range of returns of 7.77 percent to 8.38 percent for the ex ante CAPM and 6.96 percent to 8.03 percent for the ex post CAPM.

With the exception of witness Baudino's ex post CAPM analysis, all three witnesses used the ex ante CAPM model. Witness Woolridge testified that witness Avera's CAPM analysis overstated the required return for FPL because of its application to a non-utility proxy group and its reliance on an excessive market risk premium. For the same reasons discussed above in the section on the DCF model, witness Woolridge testified that witness Avera's group of non-utility companies is not an appropriate proxy to estimate the required return for FPL. Witness Woolridge also testified that witness Avera's estimate of a market risk premium of 10.0 percent is well in excess of the equity premium demanded by the market.

Witness Baudino testified that witness Avera's CAPM analysis overstated the required return for the market, and by extension, the market risk premium. Witness Avera estimated a market return of 13.2 percent and a market risk premium of 10.0 percent based on his "market" of the 346 dividend paying stocks in the S&P 500. Witness Baudino argued that if witness Avera had used a broader "market," such as the Value Line universe of companies as he had done, witness Avera's analysis would have produced results closer to the estimated market return of 10.4 percent and market risk premium of 6.5 percent reflected in witness Baudino's analysis.

Witness Avera testified that the CAPM cost of equity estimates of witnesses Woolridge and Baudino are "significantly downward biased." He also disputed their testimony regarding his methodology, stating that "the forward-looking estimate of the market rate of return used in my CAPM analysis is entirely consistent with the requirements of this approach and there is no basis to claim that it is overstated."

In addition to the DCF and CAPM analyses, FPL witness Avera also performed an Expected Earnings Approach. He testified that reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a company and its ability to attract capital. He also stated that the Expected Earning Approach is consistent with the standards for a fair rate of return while avoiding the complexities and limitations of the equity cost models discussed above. As reported in the relevant November and December 2008 editions of Value Line, the expected returns on equity for the companies in his Utility Proxy Group ranged from 8.1 percent to 15.9 percent and averaged 11.7 percent for the group. Witness Avera also noted that Value Line projected an average return on equity for the entire electric industry of 11.5 percent for 2009 and over its 2011 – 2013 forecast horizon.

Both OPC witness Woolridge and SFHHA witness Baudino challenged the reasonableness of this approach for estimating the investor required ROE for FPL. Witness Woolridge testified that witness Avera's Expected Earnings Approach "is fundamentally flawed." He stated that many of the companies in witness Avera's Utility Proxy Group have significant unregulated operations and therefore the results of this approach are unduly influenced by the profits associated with these unregulated operations. Witness Woolridge also noted that because witness Avera did not evaluate the market-to-book ratios for these companies, he cannot determine whether the past and projected returns on book equity are above or below investor required returns. To the extent the market-to-book ratios for these companies are above 1.0, witness Woolridge testified that the indicated return from this approach would exceed investors' required return.

Witness Baudino testified that all witness Avera did in this approach was report Value Line's forecasted return on book equity for 2009 and the period 2011 – 2013. He stated that forecasted returns on book equity may have nothing whatsoever to do with investors' required returns in the market place. Witness Baudino testified that we should reject this approach and recommended we utilize the range of returns produced by the DCF model in setting FPL's ROE in this proceeding.

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Witness Avera countered that the Expected Earnings Approach he used is consistent with both sound regulatory policy and the legal standards set forth in the Hope and Bluefield decisions. He also testified that there is no clear link between market-to-book ratios for electric utilities and allowed returns. Finally, witness Avera stated that neither witness demonstrated how the criterion of revenues from electric operations translated into differences in the investment risk perceived by investors.

FPL witness Avera testified that the results of his various analyses indicated that the cost of equity for FPL was in the range of 11.0 percent to 13.0 percent. In addition to the results of these quantitative analyses, he stressed that it was important for us to consider additional factors such as FPL's need to remain financially strong so it will have the ability to absorb potential financial shocks due to storm damage, fuel price volatility, and disruptions in energy supply. He also noted the challenging capital market environment and FPL's need to finance significant infrastructure investment as factors we should consider when setting FPL's ROE.

Witness Avera also testified that when a company raises equity through the sale of common stock, there are costs incurred. These flotation costs include services such as legal, accounting, and printing as well as other fees paid to brokers. He stated that, while debt issuance costs are recorded on the books of the company, amortized over the life of the issue, and recovered through the cost of debt, there is no similar accounting treatment to ensure equity flotation costs are recorded and ultimately recognized. He cautioned that unless some provision is made to recognize these issuance costs, a company's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. For this reason, witness Avera recommended incorporating a 25 basis point adjustment in determining a reasonable ROE range for FPL.

Witness Avera testified that, based on the need to remain financially strong as well as the need to recognize a 25 basis point adjustment for flotation costs, a reasonable ROE for FPL fell in the range of 12.0 percent to 13.0 percent. In light of FPL's "exemplary management," he recommended that it would be "entirely consistent with regulatory economics and past incentive mechanisms approved by the FPSC" to consider this performance when establishing a fair ROE for FPL in this range.

Finally, FPL witness Pimentel testified that there are several risk factors that are unique to FPL that should be considered by us in the determination of the Company's ROE. From the viewpoint of investors, witness Pimentel argued that FPL is more risky than other IOUs due to its geographic location, capital expenditure program, fuel supply and mix, nuclear generation, and Florida's economy. He testified that witness Woolridge's and witness Baudino's recommended returns are inconsistent with the authorized ROE of 11.25 percent recently awarded to TECO.[59] Because FPL is exposed to significantly greater risk in a number of areas when compared to TECO, witness Pimentel concluded that FPL "warrants a strong financial position and higher return on equity to meet our obligations to serve our customers."

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[59] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 48.

OPC witness Woolridge testified that it is not necessary to make an upward adjustment to the cost of equity for the recovery of flotation costs. He stated that FPL has not identified any actual flotation costs for the Company. In addition, because electric utilities have market-to-book ratios in excess of 1.0x, he testified that there should be a flotation cost reduction (and not increase) to the equity cost rate. Finally, he argued that investors also incur transaction costs when they purchase shares. If these transaction costs are taken into account, the price of shares would be higher. If these transaction costs were included in the DCF analysis, the higher effective stock prices paid for stocks would have led to lower dividend yields. This would have resulted in a downward adjustment to the DCF equity cost rate. For these reasons, witness Woolridge testified that it is unnecessary to recognize a specific adjustment for flotation costs in the determination of the investor-required ROE.

SFHHA witness Baudino also testified that an adjustment for flotation costs is inappropriate. He stated that, since witness Avera failed to provide any specific information on flotation costs incurred by FPL, his recommended adjustment is not tied to any actual costs incurred by the Company either now or in the past. Witness Baudino testified that flotation costs are already accounted for in the current stock prices and that adding an adjustment for flotation costs amounted to double recovery. For these reasons, he recommended we reject witness Avera's proposed flotation cost adjustment.

Witness Baudino testified that, while the financial markets did undergo one of the most serious periods of volatility and uncertainty in history, economic conditions have begun to stabilize. He stressed that even through the height of the financial crisis in 2008, FPL Group did not experience problems in accessing capital markets. He believes FPL's recommended ROE of 12.5 percent results in a burdensome cost of capital that is too expensive for customers to maintain. Moreover, witness Baudino testified that the cost of equity should be based on the investor-required return. He concluded that it would be inappropriate to inflate the authorized return by an arbitrary adjustment for exemplary management.

The intervenors also challenged the testimony of Company witnesses that FPL is more risky than TECO. Because TECO is rated triple B by all three rating agencies and FPL is rated single A by the same agencies, SFHHA argued that "it is unreasonable and inconsistent with investor perceptions that a company with an "A" bond rating is more risky than a company with a "BBB" bond rating like TECO, and would therefore require a higher ROE." In addition, it was noted that TECO Energy's stock price increased by 8 percent and trading volume more than doubled following the announcement of our staff's recommended ROE of 10.75 percent for TECO. FRF concluded that, because investors looked favorably on an ROE of 10.75 percent, this "lends additional support to basing the rates for FPL, which is stronger financially than Tampa Electric, on a substantially lower ROE than requested by FPL."

Each of the witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. Under normal economic circumstances, the relaxation of these assumptions for the practical application of the models is generally understood. And while the state of the economy has improved since the market disruption in the fall of 2008, the economic recovery is still somewhat tenuous. This realization does not mean

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the models no longer have value, rather, it is particularly important at this point in time to exercise informed judgment in the application of the models.

OPC witness Woolridge and SFHHA witness Baudino both argued that FPL witness Avera made certain assumptions in the application of his DCF analysis that overstated the investor-required ROE for FPL. In turn, witness Avera argued that witnesses Woolridge and Baudino made certain assumptions in the application of their respective DCF analyses that understated the investor-required ROE for FPL. As discussed earlier, all three witnesses used the same constant growth version of the DCF model. And with the exception of witness Avera's Non-Utility Proxy Group, all three witnesses used relatively similar estimates of dividend yields. The primary reason for the difference in the indicated DCF returns is attributed to differences in their respective estimates of the growth rate to include in the DCF model.

OPC witness Woolridge used an average growth rate of 5.50 percent based on the average of growth forecasts for EPS, DPS, BVPS, and the internal growth rate. The growth rates in SFHHA witness Baudino's analysis ranged from 3.75 percent to 6.25 percent and averaged 5.53 percent. These growth rates are based on growth forecasts for EPS and DPS. The average growth rates used in FPL witness Avera's DCF analysis ranged from 5.66 percent to 6.90 percent and averaged 6.32 percent. These growth rates are primarily EPS growth rates but he also included an estimate of growth based on the earnings retention method.

Because the estimated return produced by the DCF model used by the witnesses is determined by the sum of the growth rate and the dividend yield, the higher the growth rate the higher the indicated return, all else held constant. As a result, the decision regarding which DCF result is more indicative of the investor-required return for FPL comes down to which witness' estimate of growth is believed to be more appropriate.

FPL witness Avera testified that neither OPC witness Woolridge or SFHHA witness Baudino demonstrated how the criterion of revenues from electric operations translated into differences in the investment risk perceived by investors. However, a comparison of the inputs to the witnesses' respective DCF analyses provides some insight into this debate.

Both witnesses Woolridge and Baudino testified that nonregulated companies are subject to greater risk than regulated electric companies and therefore nonregulated companies will have different return requirements than regulated companies. As noted above, while the average growth rates for the respective witnesses' utility proxy groups ranged from 5.50 percent to 6.32 percent, the average growth rate for witness Avera's Non-Utility Proxy Group was 10.1 percent. While this differential in growth rates is partially offset by the relative difference in average dividend yields between the utility and non-utility proxy companies, it is clear investment analysts, and by extension investors, have a very different view of the projected earnings growth for regulated companies compared to nonregulated companies.

The existence of higher expected earnings growth for the unregulated operations versus the regulated operations of the companies included in utility proxy groups was also highlighted by the intervenor witnesses. The companies in witness Woolridge's proxy group rely on regulated electric revenues for approximately 85 percent of their revenues. In contrast, the companies in witness Avera's proxy group rely on regulated electric revenues for approximately 62 percent of their revenues. In addition, at least three of the companies in witness Avera's Utility Proxy Group rely on regulated electric revenues for less than 25 percent of their revenues.

To illustrate the impact this distinction has on the DCF-indicated return, consider the three companies that operate vertically integrated investor owned utilities (IOUs) in Florida.[60] All three witnesses included FPL Group, the Southern Company, and Progress Energy in their respective utility proxy groups. Both the Southern Company and Progress Energy have divested nearly all of their unregulated operations and rely on regulated operations for essentially all of their revenues. In contrast, depending on the source,[61] FPL Group relies on unregulated operations for 25 to 30 percent of its revenues.

The difference in expected earnings growth between the three companies is telling. Progress Energy has expected earnings growth estimates ranging from 5.0 percent to 6.0 percent and the average of the expected earnings growth rates is 5.3 percent. The Southern Company has expected earnings growth estimates ranging from 5.2 percent to 5.8 percent and the average of the expected earnings growth rates is 5.5 percent. In contrast, FPL Group has expected earnings growth estimates ranging from 9.3 percent to 10.0 percent and the average of the expected earnings growth rates is 9.6 percent. This difference between the expected earnings growth for "pure plays" such as Progress Energy and the Southern Company and more diversified companies such as FPL Group is an important consideration in the determination of the ROE for FPL because the ROE authorized in this proceeding will only reflect the investor-required return for the regulated operations of FPL and not the required return for FPL Group, the consolidated entity.

In defense of his reliance on a Non-Utility Proxy Group to estimate the investor-required return for FPL, witness Avera testified that the Bluefield decision did not restrict consideration of comparable risk just to other utilities. He is correct. There is no expressed requirement in Bluefield that comparable companies be limited to utilities. However, as noted in the pertinent passage from the Bluefield decision that follows, the determination of a comparable company is not without limits:

> 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 such*

[60] We note that, while Tampa Electric Company also operates in Florida, none of the three witnesses included TECO Energy in their utility proxy group.
[61] AUS reports that FPL Group derives 70 percent of its revenues from regulated electric operations. S&P reports that FPL is responsible for 75 percent of FPL Group's consolidated credit profile. According to FPL Group's 2008 Annual Report to Shareholders, FPL accounted for 76 percent of FPL Group's consolidated revenues in 2007 and 71 percent of its consolidated revenues in 2008.

> *profits as are realized or anticipated in highly profitable enterprises or speculative ventures.* [62]

(emphasis added)

Witness Baudino testified that the bulk of witness Avera's results suggest a lower ROE, more in the range of 10.5 percent to 11.7 percent if the results of his Utility Proxy Group were used. Witness Baudino stated that only by considering the results of his Non-Utility Proxy Group can witness Avera support a return above 12.0 percent. Witness Baudino testified that non-utility companies have higher overall risk structures, and thus higher required returns, than low-risk utilities like FPL. Moreover, because FPL has one of the strongest bond ratings in the utility industry, he argued that FPL should have a lower required return than the average utility.

Both OPC witness Woolridge and SFHHA witness Baudino challenged the reasonableness of FPL witness Avera's Expected Earnings Approach for estimating the investor-required ROE for FPL. Witness Woolridge testified that many of the companies in witness Avera's Utility Proxy Group have significant unregulated operations and therefore the results of this approach are unduly influenced by the profits associated with these unregulated operations. Witness Baudino testified that forecasted returns on book equity may have nothing whatsoever to do with investors' required returns in the market place. Witness Avera countered that the Expected Earnings Approach he used is consistent with both sound regulatory policy and the legal standards set forth in the Hope and Bluefield decisions.

Witness Avera is correct that the Expected Earnings Approach is a generally recognized method for estimating ROE and is consistent with the "corresponding risk" standard of the Bluefield decision. However, witness Avera acknowledged that the expected returns shown in his analysis were based on the results of both the regulated and unregulated operations of the companies in his Utility Proxy Group. To the extent that the greater risk associated with unregulated operations exerted upward pressure on the expected returns for the consolidated companies, the indicated return from this approach overstates the investor-required return for the regulated operations of FPL.

Each of the witnesses made arguments for including and not including an allowance for the recovery of flotation costs in the determination of the ROE. While it has been our practice to recognize an adjustment for flotation costs in certain applications, the determination of an authorized ROE by a regulatory commission in an evidentiary proceeding very seldom involves the level of specificity that would permit the itemization of a specific allowance for flotation costs. In this context, the debate over whether to include or not include an allowance for flotation costs is similar to the debate over whether to use an annual or quarterly DCF model, or a blended growth rate or an earnings-only growth rate in the DCF analysis. The ROE we approved in this docket does not specifically recognize or exclude an allowance for flotation costs but rather represents a blend of the results of the witnesses' analyses.

[62] Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 692–693 (1923).

Company witnesses testified that, due to risk factors unique to FPL, we should set an ROE for FPL higher than the return recently authorized for TECO. The ROE set in this proceeding is based on the record in this case. While the record in the TECO case was developed over the period from August 2008 through January 2009 and a decision was rendered in March 2009, the record in FPL's case was developed over the period March 2009 through October 2009 with a decision in January 2010. Conditions change over time and an ROE that was reasonable for a particular company at a particular point in time may or may not be relevant to the investor-required return for a different company at a different point in time.

As for the argument that FPL is so uniquely riskier than other IOUs that it requires an ROE well above the average ROE authorized for other IOUs, the record in this case does not bear this out. Other than the Company's geographic location, it was demonstrated that the majority of the companies in witness Avera's Utility Proxy Group were also exposed to the same or similar risk factors related to significant capital expenditure programs, issues related to fuel mix, managing O&M expense, owning and/or proposing nuclear generation, dealing with weather related service interruptions, and the need for a regulatory environment supportive of credit quality. Witness Avera testified that, to the extent that cost recovery clauses and other adjustment mechanisms are prevalent across the industry, the risk mitigation benefits of these mechanisms have already been reflected in the cost of equity estimates. Similarly, since the risk factors suggested by the Company are systemic to the industry and are not unique to FPL, investors' expectations regarding these risk factors have also been captured in the results of the cost of equity models. Moreover, the rating agencies conduct quantitative and qualitative assessments of the Company's business and financial risk position. FPL is one of the highest rated IOUs in the nation. Just as we have resisted certain proposed adjustments to the Company's capital structure that would exert downward pressure on the Company's financial position, it is equally important to resist efforts to overstate the Company's relative risk profile to justify a higher ROE.

Due to the reliance on the results of DCF and CAPM analyses applied to unregulated companies, the Company's requested ROE of 12.5 percent overstates the current investor-required ROE for FPL. Exhibit 462 reported the authorized ROEs set during 2009 for the electric utilities followed by Regulatory Research Associates (RRA). The ROEs set during 2009 ranged from a low of 8.75 percent to a high of 11.5 percent and averaged 10.51 percent for the group. While we do not believe the authorized ROE for FPL should be based upon the average return set by other Commissions during 2009, we do not believe returns significantly above or below this level are indicative of the investor-required return for FPL, either.

Finally, in making our decision, we are cognizant of the prevailing economic realities that Florida electric customers and the Company face right now. These difficult economic times must be faced by both the electric customers and the Company alike. We know from record testimony that FPL's customers in this market are experiencing economic hardship, as Florida residents are throughout the state. And yet again, we are conscious of the need to provide an equitable and fair rate of return for FPL. It is our responsibility as an economic regulatory agency, to be cognizant of the prevalent economic conditions and to establish a return on equity that will be fair to the company and fair to the customers alike.

Based on the foregoing, we approve an authorized ROE of 10.00 percent with a range of plus or minus 100 basis points. In arriving at this return, we weighed the identified strengths and weaknesses associated with the respective witness' analyses. We also took into account FPL's proposed construction program and its need to access the capital markets under reasonable terms. In addition, when determining the ROE, we considered the equity ratio. At an equity ratio of approximately 59 percent on a Commission-adjusted basis and approximately 56 percent on an S&P-adjusted basis, we find that an authorized ROE of 10.00 allows FPL the opportunity to earn a fair and reasonable return for the provision of regulated service.

Weighted average cost of capital

Each party's recommendation on the appropriate weighted average cost of capital is a mathematical computation based upon their recommendations on each of the prior issues regarding cost of capital. FPL originally proposed a weighted average cost of capital for 2010 of 8.00 percent. However, due to certain revisions, FPL amended its proposed weighted average cost of capital to 7.85 percent. OPC proposed a weighted average cost of capital of 6.14 percent for 2010. SFHHA proposed a weighted average cost of capital of 6.34 percent.

Our determination of the weighted average cost of capital is a result of our previous decisions regarding the cost of capital. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2010, the appropriate weighted average cost of capital for FPL for purposes of setting rates in this proceeding is 6.65 percent. Our decision is demonstrated in Schedule 2 attached to this order.

NET OPERATING INCOME

Inflation and customer growth

We reviewed the inflation and customer growth rate projections for 2010 contained in MFR Schedule F-8. The 2010 inflation and customer growth rates were sponsored by FPL witness Morley and provided in MFR Schedule F-8. In her direct testimony, witness Morley testified that FPL incorporated several measures of inflation into its budgeting assumptions including the Consumer Price Index (CPI), the Producer Price Index (PPI), and the GDP Deflator. These budgeting assumptions were based upon input from Global Insight and other publically available sources. For 2009 and 2010, FPL projected inflation, as measured by the CPI, to increase at a two percent annual rate. The inflation projections contained in MFR F-8 are consistent with the projections of independent sources such as Global Insight and other publicly available sources. Therefore, the inflation assumptions contained in MFR F-8 are appropriate for the 2010 test year.

We also reviewed the forecast model and assumptions used to project customer growth rates through 2010. FPL's customer growth rates for 2009 and 2010 were derived from FPL's customer model. Based on the output of this model, FPL projected the number of customers to increase by 0.2 percent in 2009, and increase by 0.6 percent in 2010. These growth rates represent reasonable expectations of customer growth through 2010. Accordingly, we approve

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the inflation and customer growth factors for 2010 as provided in MFR Schedule F-8 as appropriate.

Capacity charges

FPL witness Ousdahl explained that the Company was requesting to transfer $56.9 million associated with St. Johns River Power Park (SJRPP) from base rates to the capacity clause. According to witness Ousdahl, the reason for this transfer was:

> . . . in order to be consistent with the recovery mechanism for other capacity arrangements and to comply with the Commission's decision in Order No. 25773, Docket No. 910794-EQ which stated in part "that capacity related purchased power costs not currently being recovered in any manner may be included in the capacity recovery factor. Those costs currently being recovered in base rates will remain in base rates until the utility's next general rate case. A net amount of $56.9 million was included for recovery in 1988 base rates as explained in FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI.

MFR Schedule B-2, for the projected 2010 test year, showed adjustments made to transfer costs associated with SJRPP from rate base to the capacity clause. Rate base was increased by $54,511,000 for 2010 on a jurisdictional basis.

MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to net operating income related to the transfer of cost associated with SJRPP from base rates to the capacity clause. Net operating income was increased by $34,979,000 for 2010 on a jurisdictional basis.

We find that capacity charges associated with SJRPP shall be treated consistently with other capacity arrangements and shall be included in the capacity clause. This is the first general rate case in which we have had the opportunity to transfer these charges from base rates to the capacity clause. Accordingly, the adjustments made by FPL for the St. Johns River Power Park (SJRPP) from base rates to the capacity clause are approved.

Fuel Adjustment, Conservation, Capacity, and Environmental cost recovery clauses

FPL asserted that it made appropriate adjustments to remove revenues and expenses recoverable through the Fuel Adjustment, Conservation, Capacity, and Environmental Cost Recovery Clauses. FPL offered the testimony of witness Ousdahl, as well as MFRs and exhibits to support its position. FPL witness Ousdahl testified that ". . . Exhibit, KO-3 [hearing Exhibit 119] lists the MFRs that directly support the overall 2010 jurisdictional revenue requirement increase of $1.044 billion requested by FPL. Those MFRs include schedules that support adjusted jurisdictional rate base of $17.1 billion, adjusted jurisdictional net operating income of $726 million . . ." Exhibit 180 contained a complete set of FPL's MFRs, including those listed in Exhibit 119 mentioned in Witness Ousdahl's testimony above.

MFR Schedule B-2, for the projected 2010 test year, showed the adjustments to rate base that FPL made related to the transfer of cost associated with each of the aforementioned clauses from base rates to the appropriate clause. For the Fuel Adjustment Clause, rate base was decreased by $102,000 for 2010 on a jurisdictional basis. For the Conservation Cost Recovery Clause, rate base was decreased by $23,759, for 2010 on a jurisdictional basis. For the Environmental Cost Recovery Clause, rate base was decreased by $593,376,000 for 2010 on a jurisdictional basis. No adjustments to rate base were made for the Capacity Cost Recovery Clause.

MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to net operating income that FPL made related to the transfer of cost associated with each of the aforementioned clauses from base rates to the appropriate clause. For the Fuel Adjustment Clause, net operating income was decreased by $1,262,000 for 2010 on a jurisdictional basis. For the Conservation Cost Recovery Clause, net operating income was decreased by $1,808,000 for 2010 on a jurisdictional basis. For the Capacity Cost Recovery Clause, net operating income was decreased by $32,323,000 for 2010 on a jurisdictional basis. For the Environmental Cost Recovery Clause, net operating income was decreased by $78,999,000 for 2010 on a jurisdictional basis.

We have reviewed the MFRs and discovery responses concerning the adjustments for each of the aforementioned clauses and find that they are correct. Accordingly, FPL's proposal to transfer revenue, expenses and investment associated with the fuel clause from base rates to the Fuel Adjustment Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with the conservation cost recovery from base rates to the Conservation Cost Recovery Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with capacity cost recovery from base rates to the Capacity Cost Recovery Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with the environmental cost recovery from base rates to the Environmental Cost Recovery Clause is approved.

<u>Commercial/Industrial Demand Reduction Rider</u>

FPL witness Ousdahl proposed adjustments to the Company's forecasted revenues for the 2010 test year to the Commercial/Industrial Demand Reduction (CDR). MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to revenue and net operating income that FPL made related to the CDR. Revenue was reduced $10,306,000 and net operating income was decreased by $6,330,000 for 2010 on a jurisdictional basis. Witness Ousdahl explained that:

> CDR is a voluntary energy management program that provides customers bill credits, while helping FPL efficiently manage the supply of electricity by allowing the Company to unilaterally reduce power usage during peak demand periods, capacity shortages, or system emergencies. FPL records an offset to its base revenues for the benefits received by those customers who participate in the CDR program. FPL inadvertently excluded the debit to base revenues in its 2010 Test Year and 2011 Subsequent Year forecasts. Therefore, FPL has included a reduction in base revenues of $10.3 million for the 2010 Test Year and $10.6 million for the 2011 Subsequent Year.

We have reviewed the Company's forecast and it does reveal that the effects of the CDR were not originally included in the forecast by FPL witness Morley. The CDR was inadvertently excluded. Accordingly, FPL's adjustments to operating revenue for the 2010 test year to include the effects of the C/I Demand Reduction Rider Incentive Credits are approved.

Late payment fee revenues

In its forecasted revenues, FPL included a 30 percent reduction in late payment fees and a 2 percent increase in write-offs of late payment revenues due to the proposed increase in the late payment fee. FPL proposed a change in its revenues relating to late payment charges to recognize a proposed customer behavior modification plan which FPL argued would discourage customer late payments. FPL witness Santos described the Company's proposed change to its charge for late payments as follows:

> FPL currently charges 1.5% for late payments, but is proposing the greater of 1.5% or $10. Driven largely by the deteriorating economy, FPL has seen a steady increase in the number of customers making late payments. The percent of customers with late payments has increased from 21% in 2006 to 24% in 2008. This is an increase of 150,000 customers on average per month.

OPC witness Brown testified that FPL had understated its projected revenue from late payment.

> . . . in projecting the late payments fees for the test years, FPL has assumed that percentage of late paid accounts will remain at the same levels as the 2008 experience. In addition, the Company has offset the increased late payment fees by a 2% write-off rate and a 30% "behavior change" associated with accounts that would be subject to the minimum charge. These adjustments have resulted in an understatement of the late payment revenues under the revised structure.

According to witness Brown, FPL did not provide any justification for its assumption that the implementation of the $10 minimum late fee would cause 30 percent of the affected customers to pay their bills on time which would reduce the percent of late paid bills to pre-2007 levels.

OPC witness Brown recommended eliminating the two percent write-off adjustment, which should already be incorporated into the uncollectible accounts expense. She also recommended eliminating the 30 percent behavior modification adjustment and, instead, proposed using an average of the 2007 and 2008 late payments as a percentage of total bills. Under this approach, 20 percent of customer bills are assumed to be late which is less than the 22.3 percent level experienced in 2008.

OPC witness Brown's recalculated revenues from late payment fees was $25,024,251 greater than FPL's estimate for 2010.

FPL witness Santos testified in her rebuttal that:

> The purpose of changing the late payment charge to have a minimum of $10 is to change behavior and induce more timely payment. . . By minimizing the behavior change assumption of 30%, Ms. Brown effectively diminishes the impact that the late payment charge is specifically designed to achieve. . . FPL's use of an assumed behavior change of 30% is therefore quite conservative because it is less than half of the 65% change expected when applying the electricity demand elasticity.

We disagree with the Company's analysis of its customer behavior modification plan. The Company's analysis of behavior change based on the electricity demand elasticity suggested that there would be a behavior change of 65 percent. We believe this percentage to be extremely high and in our opinion makes the analysis somewhat suspect. We do not find it supportive of the Company's 30 percent behavior change. No analyses was presented for the 30 percent behavior change in FPL's original filing.

We agree with witness Brown's recommendation to eliminate the two percent write-off adjustment and to include the effects of uncollectibles in the uncollectible account. This approach is consistent with other revenue adjustments. We also agree with witness Brown's approach to recognize revenue associated with late payment fees based on the average of 2007 and 2008. Witness Brown's approach used actual late payments and still recognized a decrease in the number of customers paying late compared to 2008.

FPL proposed some additional changes to its late payment revenues based on corrections it discovered during the proceeding. FPL witness Ousdahl sponsored hearing Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified some additional adjustments to the Company's original filing. Exhibit 358 summarized the additional adjustments to rate base, net operating income, and capital structure that FPL made to its original filing. Items 6a and 10 of Exhibit 358 addressed some additional changes to FPL's proposed adjustment to net operating income for revenues associated with late payments.

Item 6a of Exhibit 358 showed FPL's proposed adjustments due to an over-statement of late payment revenue. According to FPL, late payment revenues were overstated because they were based on an older version of the revenue forecast than what was used to develop the final projections. Item 6a resulted in an adjustment to decrease late payment fee revenue by $7,386,000 for the 2010 test year.

Item 10 of Exhibit 358 showed FPL's proposed adjustments due to an under-statement of late payment revenue. According to FPL, late payment revenues were inadvertently reduced by expected bad debts on the full amount of late payment revenues rather than on the incremental change in late payment revenues. Item 10 resulted in an adjustment to increase late payment fee revenue by $751,895 for the 2010 test year.

We find that FPL's additional adjustments made in its Exhibit 358, which were made to correct its original filing, are reasonable and appropriate.

Based on the foregoing, we find that FPL's adjustments to correct the original forecast for Late Payment Revenue proposed in Item 6a and Item 10 of Exhibit 358 are appropriate and we approve those changes. We agree with OPC's proposal to adjust the forecast of late payment revenues based on 2007 and 2008 actual experience. Accordingly, we approve a net adjustment to net operating income to increase late payment revenue for the 2010 test year by $18,390,146.

Revenue Forecast

Our decision regarding the 2010 revenue forecast is a result of our discussion of several items in this Order. Our revenue forecast is based on our analysis and decisions regarding forecasts of customers for the 2010 test year, revenue responsibility for transmission investments, and late payment fee revenues. No further changes to our revenue forecast are necessary as the changes are captured in our discussions listed above and are reflected cumulatively in our calculation of net operating income totals listed below.

Total Operating Revenue

We were asked to determine if FPL's proposed $4,114,727,000 total operating revenue for 2010 was appropriate. Our decision regarding what FPL's appropriate total operating revenues for 2010 is a culmination of our other decisions in this Order. Based on our decisions, the appropriate total operating revenue is $4,136,478,146 for the 2010 projected test year and, is shown on Schedule 3, attached to this Order.

Charitable contributions

FPL witness Ousdahl sponsored Exhibit 117, which included MFR Schedule C-18 for the 2010 test year. This MFR was also contained in Exhibit 180. MFR Schedule C-18 required the Company to "Provide a schedule, by organization, of any expenses for lobbying, civic, political and related activities or for civic charitable contributions included for recovery in cost of service for the test year and the most recent historical year." FPL's response to MFR Schedule C-18 for the 2010 test year stated "Because of prior Commission decisions, the Company did not include any expenses for lobbying, civic, political and related activities, or for civic charitable contributions in determining Net Operating Income for 2010. All are accounted for "below the line."

We find that, with the exception of contributions to FPL's Historical Museum, FPL has followed our direction provided through past orders regarding the treatment of charitable contributions. FPL witness Ousdahl testified that it was not appropriate to adjust the test year expenses to remove the contributions made to the FPL Historical Museum by FPL. According to witness Ousdahl:

> The FPL Historical Museum is a subsidiary of FPL that is charged with maintaining records and artifacts associated with the Company's long history in the state of Florida. These activities are important to the preservation of the historically significant information about the Company and the industry from its beginning in the early 20th century until today. The FPL Historical Museum costs

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> are incurred by FPL and recorded as legitimate FPL operating costs. Therefore, it is inappropriate to make an adjustment to move such costs below the line and treat them as charitable donations.

Witness Dismukes argued that the payments to the FPL Museum appear to be the same as charitable contributions and should be treated as such. She recommended an adjustment for the costs recorded above the line for the FPL Historical Museum, Inc. She stated that:

> I am recommending that the Commission reduce test year expenses by $45,470 in 2010 and $46,764 in 2011 for the contributions made by FPL to the Historical Museum. (Response to OPC Interrogatory 69 and AG Interrogatory 27.) According to FPL, the museum maintains records and artifacts concerning the electric industry as well as FPL historical records. (Supplemental Response to OPC Interrogatory 27.) The museum is a not-for-profit affiliate. FPL pays the operating costs of the museum and records them to FERC Account 930. These costs are reflected on the financial statements of the museum as a contribution. (Second Supplemental Response to OPC Interrogatory 69.)

The record reflects that FPL Historical Museum is a not-for-profit subsidiary of FPL. FPL pays the operating cost of the museum. However, the museum records these amounts as contributions. The true purpose of the Museum should dictate how its costs are recovered. According to FPL, the museum is responsible for "maintaining records and artifacts associated with the Company's long history" and "records and artifacts concerning the electric industry as well."

The minimum standards for the preservation of records of public utilities are described in great detail in the Code of Federal Regulations Part 125 (Code). The costs to maintain FPL's books and records, as described in the Uniform System of Accounts, are recorded as administrative and general expenses. The Code does not require that utilities maintain "records and artifacts concerning the electric industry."

FPL did not explain exactly what records were being maintained by the FPL Museum. Also, FPL did not explain why the responsibility "for maintaining records and artifacts" was established as a separate not-for-profit entity and named the FPL Historical Museum. It would appear that the FPL Museum is designed more for the enhancement of FPL's corporate image than mere records storage.

Based on the foregoing, we find that the payments to FPL Museum are charitable contributions. We have consistently held for many years now that such costs should be borne by stockholders of a company rather than by ratepayers, since the latter have no choice in the charity.[63] Accordingly, we reduce other expenses by $45,470 for the 2010 test year.

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[63] Order PSC-07-0671-PAA-GU, issued August 21, 2007, in Docket No. 070107-GU, <u>In re: Investigation into 2005 earnings of the gas division of Florida Public Utilities Company</u>.

Aviation costs

FPL removed the full amount of aviation costs for the 2010 test year from its rate increase request as a concession and to assist in the completion of the hearing. We approved FPL's motion to withdraw all aviation costs included in the 2010 test year. The Company's original MFRs are adjusted to show the effect of removing the Company's aviation costs as follows:

FPL's removal of aviation costs reduced operating expenses and depreciation expense by $1,633,916 and $2,092,009, respectively, for the 2010 test year. It also reduced plant in service and depreciation reserve by $53,268,205 and $27,853,907, respectively, for the 2010 test year. We approve those adjustments.

The removal of aviation costs had the effect of increasing FPL's originally requested net operating income before taxes by $3,725,925 for the 2010 test year. It also had the effect of reducing FPL's originally requested rate base by $25,414,298 for the 2010 test year.

Advanced Metering Infrastructure (AMI) meters included in net operating income

As noted above, FPL plans to install smart meters over a five year period. FPL contended that it appropriately included the cost savings for AMI meters in net operating income. FPL stated that the cost savings associated with AMI meters will only be realized after the meters are deployed and after all components and supporting processes are fully developed, tested, and implemented. According to FPL, the claims made by SFHHA to prorate the savings as the meters are installed would be unrealistic.

SFHHA argued that the savings should be proportional to the costs. SFHHA argued that the mismatch between savings and costs deprives FPL's ratepayers of the full operational savings to which they are entitled. SFHHA argued that net operating income should reflect 16.9 percent of the annualized O&M expense savings, or $6.084 million.

FPL Witness Santos testified that the savings from AMI will only happen after the completion of the entire AMI project. AMI savings will not happen in ratio to the implementation of the meters. Witness Santos testified that the savings will only occur after an integration of software, completion of new databases, implementation of cyber security, development of measures to maximize new functionality, and training on the new systems and processes is completed. The witness testified that the project could be deferred, but FPL believed that the technology was ready, and that FPL wanted to be able to help shape the market. Table 23 on the following page shows the capital expenditures and the associated savings from AMI implementation.

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Table 23

Deployment	2009	2010	2011	2012	2013	Total
Meters (Thousands)	170	1,128	1,099	1,076	873	4,346
Capital (Millions)	$43.7	$168.5	$158.7	$151.5	$122.5	$645
O&M (Thousands)	$2,274	$6,883	$8,910	$11,882	$10,458	
Savings (Thousands)	($167)	($418)	($4,700)	($18,203)	($30,401)	
Net O&M (Thousands)	$2,106	$6,465	$4,210	($6,321)	($19,943)	

SFHHA witness Kollen testified that recognizing 1.2 percent of the savings and 16.9 percent of the capital expenditure in a test year was unreasonable. Witness Kollen testified that the meters, when installed, would realize immediate savings. The witness contended that the savings should be matched to the capital expenditures.

We decline to adjust net operating income in the test year for the future savings from AMI. The expenditure in AMI will lead to increased savings and should provide the customer with more information. The implementation of AMI will allow the Company to provide more service from a remote location. The delay of the implementation of AMI is not in the best interests of the Company or the ratepayers. Future savings from AMI can reduce the impact of future costs incurred by FPL.

Based on the foregoing, we find that the savings from smart meters have been appropriately included in rate base. It is unrealistic to assume that the savings from AMI implementation will happen as soon as the meters are installed. The AMI project is prudent and should not be delayed. We recognize that the project will have greater savings in the future, but we do not believe an adjustment is warranted. We direct the Company to bring us a program that will help customers take advantage of the potential energy savings from AMI.

Bad debt expense

We were asked to determine the appropriate amount of bad debt expense. FPL proposed bad debt expense of $29,903,552 for 2010, which included adjustments made by FPL in its Exhibit 358. OPC argued that the 2010 bad debt expense was $19,751,466. OPC argued that FPL overstated its bad debt expense. OPC witness Brown testified that:

> FPL used a regression analysis to forecast the uncollectible accounts expense using historical and projected data such as the real price of electricity, kWh sales, and unemployment. . . . the assumptions used in the regression model were apparently made prior to economic changes that were utilized by FPL in preparing other components of its filing. These assumptions would cause the overstatement of bad debt.

FPL witness Santos testified that:

> Ms. Brown correctly points out that the level of kwh sales and real price of electricity used in the regression model to predict bad debt are higher than those used for other purposes in FPL's final projection for the Test Years. However, she incorrectly concludes that the bad debt calculation would have been reduced significantly if later, lower estimates of kwh sales and real price of electricity had been used. . . . For consistency in FPL's filing, it is necessary to use all variables-- kWh sales, real price, and the other economic variables-- from the same vintage. . . . FPL is reflecting this increase in bad debt expense as part of FPL witness Ousdahl's Exhibit KO-16 [358], Identified Adjustments.

FPL witness Santos explained that FPL used regression analysis to forecast bad debt expense. According to witness Santos, projected bad debt expense was based on a model using historical and projected data such as the inflation adjusted price of electricity, kWh sales, and unemployment. She stated that:

> . . . we have found that there are two main drivers of a customer's ability to make payment, the dollar amount of the bill and the economic conditions currently impacting their ability to pay. These two variables are subject to changes overtime which may not be reflected in the historical write-off experience, especially during periods of economic instability.

OPC Witness Brown testified that the 2010 Test Year net write-offs should then be reduced by the impacts of additional automatic bill payments and the incremental avoided write-offs due to the remote connect switch (RCS).

FPL witness Santos explained that the regression model used to forecast bad debt expense included growth in automatic bill payments over the last few years. As a result, the model already assumed a rate of growth for automatic bill payments in 2010.

FPL witness Santos further explained that the RCS was a new technology in the meters that FPL was deploying as part of the AMI project. She noted that witness Brown's recommendation for a greater RCS write-off savings would require an earlier deployment of RCS than was planned.

FPL's proposed bad debt expense was adjusted to include corrections to the direct testimony and MFR filings. FPL witness Ousdahl sponsored hearing Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified appropriate additional adjustments to the Company's filing. Hearing Exhibit 358 summarized the additional adjustments to rate base, net operating income, and capital structure that FPL proposed be made to its original filing.

Item 6b of Exhibit 358 showed FPL's proposed adjustment to bad debt expense to correct an under-statement. According to Exhibit 358, FPL's bad debt expense was understated because it was based on an older version of the revenue forecast and economic variables than what was

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used to develop the final projections. Item 6b resulted in an adjustment to increase bad debt expense by $3,805,000 for the 2010 test year.

We find that the recommendation by OPC concerning the automatic bill payments has been incorporated into the adjusted forecast by FPL. We find that FPL's adjustments to correct the original forecast for bad debt expense proposed in Item 6b of Exhibit 358 is appropriate and we approve the same. It appears that OPC's proposed adjustment to reflect the impacts of additional automatic bill payments and the incremental avoided write-offs due to the RCS would require the Company to deploy the AMI project faster than planned. Accordingly, we decline to adopt OPC's proposed adjustment. Based on the foregoing, we increase bad debt expense by $3,805,000 for the 2010 test year, as proposed by FPL in Item 6b of Exhibit 358.

Clause revenue

FPL proposed to make an adjustment to net operating income to remove those portions of bad debt expense associated with clause revenue that are currently being recovered in base rates and include them as recoverable expenses in the respective recovery clauses. FPL witness Ousdahl explained that "the Company's 2010 and 2011 forecast includes an estimate of bad debt expense on its total revenues, including revenues generated from clauses, in accordance with current practice." However, the Company proposed an adjustment to remove estimated bad debt expense related to clause revenues from base rates and include them with the recovery clauses. Witness Ousdahl stated "including the clause bad debt as a clause recoverable cost ensures that the estimate is consistent with and related to the clause revenues that are not collected."

OPC witness Brown recommended that the uncollectible accounts expense remain in base rates for two reasons. First, FPL's proposed treatment creates an additional need for regulatory oversight and adjustments. Witness Brown testified that:

> In order to apply this process to the clauses, FPL would need to develop separate write-off rates and establish separate accrual provisions for each clause as the clause components of uncollectible accounts would vary by month and by customer. FPL has not proposed a process for recognizing the uncollectible accounts expenses through the various clauses.

Second, Witness Brown pointed out that the transfer of the uncollectible accounts expense to the clauses would increases the portion of FPL's revenue that was collected through clauses. She stated that "If 61% of the uncollectible accounts are simply passed through a clause, then FPL's incentive to continue its efforts to reduce uncollectible accounts is reduced."

We agree with OPC's reasoning. FPL's proposed treatment would create an additional need for regulatory oversight. Allocating a portion of bad debt to the clauses would create a disincentive to reduce bad debt and require additional regulatory vigilance. Perhaps the strongest reason not to move a portion of bad debt from base rates to several different clauses is found in FPL's own position that the rate of bad debt exposure is no different for a dollar of fuel revenue than for a dollar of base revenue. Accordingly, there is no compelling reason to move the bad debt expense to clause recovery. Our decision here is consistent with our recent Order No. PSC-

09-0411-FOF-GU,[64] wherein we denied Peoples Gas' proposal to move a portion of bad debt expense from base rates to the Purchased Gas Adjustment Clause (PGA).

Based on the foregoing, we hold that bad debt expense shall remain in base rate and that no portion of it will be allocated to the recovery clauses. Accordingly, bad debt expense is increased by $16,893,000 for the 2010 test year.

Payroll

For the 2010 test year, FPL projected it would have 11,111, employees consisting of 4,943 exempt (salaried) employees, 2,628 non-exempt (hourly) employees, and 3,540 union employees. However, we were presented with evidence showing that during the five years ending 2008, FPL's actual full-time equivalents ranged from a low of 1.71 percent below target in 2004 to a high of 2.48 percent below target in 2007, with an average of 2.08 percent below target over the 5-year period. We were asked to determine if any adjustments to FPL's payroll were necessary to reflect the historical average level of unfilled positions and jurisdictional overtime.

OPC contended that the dollars associated with unfilled positions should be removed because they would not be incurred in 2010. The record indicated that historically, FPL has consistently run under the number of budgeted employees. Therefore, it stands to reason that FPL's historical level of overtime included the time necessary to cover the work that would be performed by the unfilled positions.

To correct FPL's double counting, OPC witness Brown made changes to the actual unfilled historic data to eliminate discrepancies, and staffing changes that were disclosed in discovery. She then developed a factor that could be applied to the projected test years to produce a projected number of unfilled positions. She proposed an adjustment to reduce payroll and benefits based on a modified historical average of 1.59 percent. This percentage represented the difference between the budgeted numbers of employees compared to the expected number of actual employees that would be in place during the test year.

Witness Brown proposed an offsetting adjustment to increase overtime for the Nuclear and Transmission Business Units due to the unfilled positions. This offset was calculated to recognize that these business units based their overtime projections, in part, on the full budgeted staff levels.

Exhibit 236, page one, sponsored by Witness Brown, showed OPC's proposed adjustment to reduce payroll and associated benefits by the projected level of unfilled positions. The total jurisdictional adjustment to expenses was a $12,507,000 decrease for the 2010 test year.

[64]Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket 080318-GU, In re: Petition for rate increase by Peoples Gas DOCKET NO. OS031S-GU System, p. 29.

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Exhibit 236, page 2, sponsored by Witness Brown, showed OPC's proposed adjustment to increase overtime that offsets the adjustment for unfilled positions. Witness Brown testified that "[t]his offset to my adjustment was calculated to recognize that these business units based their overtime projections, in part, on budgeted staff levels. . . . FPL's other business units primarily used historical levels of overtime without adjustment for increased staffing levels." OPC's proposed adjustment for overtime increased jurisdictional expenses by $3,261,989 for the 2010 test year.

According to OPC witness Brown's testimony, except for the departments she specifically adjusted, FPL used the historical levels of overtime to project the overtime for the 2010 test year. This resulted in the time to perform the work of the unfilled positions being counted twice. First, the forecasted overtime included the time to perform work for unfilled positions based on historical averages. Second, the costs of the positions that would not be filled were included in the forecast.

We agree that OPC's witness Brown effectively showed that FPL's method in budgeting for payroll was flawed because it failed to accurately take into account unfilled positions and because by projecting overtime from historical data, FPL double counted its costs. It is clear from the record that FPL will not employ the number of positions that it forecasted for the 2010 test year. However, we do not believe that OPC's modified historical average was representative of the 2010 test year either. Prior to making its other adjustments, OPC took an average of the 5 years prior to and including the historic test year. That average was 2.08 percent below target. However, we find that the data from 2007 is more representative of the number of unfilled positions that FPL will have in 2010. We heard testimony from FPL indicating it was taking a more conservative approach to filling vacant positions since 2008. Accordingly, we find that 2007 data is most representative of the number of unfilled positions. Based on the foregoing, we reduce FPL's proposed O&M expense for payroll by $15,392,467, on a jurisdictional basis and taxes other than income taxes by $882,729, on a jurisdictional basis for the 2010 test year to reflect historically unfilled positions.

Productivity improvements

We were asked to consider whether we should reduce FPL's expenses for productivity improvements given the Company's lower historical rate of growth in payroll costs. SFHHA witness Kollen testified that "[t]he Company reflected significant increases in payroll costs, including inflation and merit increases and staffing increases, but did not explicitly reflect an offset against these proposed expense increases for productivity improvements." Witness Kollen explained that the Company achieved productivity through capital investment in assets that reduced maintenance requirements and allowed fewer employees to do more in less time. Witness Kollen also stated that FPL's adoption of best practices in managing processes should reduce expenses.

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FPL disagreed. FPL witness Barrett stated:

> A better measure of the Company's productivity is payroll dollars per customer rather than payroll per hour. The Company's goal is to serve customers reliably at a reasonable cost, not to achieve a particular payroll cost per hour. . . . the projected increases in base pay per customer in 2010 and 2011 are lower than the average increase in that metric from 2006 to 2008.

We find that productivity is an important metric that should be tracked by utilities as a significant guide as to whether the utility is performing as it should from year to year. However, productivity can be measured in many ways and must be fully understood before conclusions can be drawn concerning its applicability to any given situation.

In this case, we agree that a Company's goal is to serve customers reliably at a reasonable cost. The Company has shown that its base pay per customer in 2010 is lower than the average increase in that metric from 2006 to 2008. While we do not approve a productivity adjustment based on the record in this case, we will continue to review productivity in the future. Based on the foregoing, we decline to make a productivity adjustment to expenses.

Forecasted operating and maintenance expenses

FPL proposed to increase its forecasted O&M expenses due to estimated needs for nuclear production staffing. FPL witness Stall testified that:

> It can take as long as eight to nine years to develop an operator candidate into an SRO [Senior Reactor Operator]. In general, the cost to FPL of training, examination development, and licensing of a single candidate who starts without a license to obtain an SRO license is approximately $160,000, not including payroll and benefits of each candidate, or the fees charged by the NRC for its review of the examination materials and oversight of the training and examination process. Additionally, FPL has been required to increase licensed operator class size (and hire additional training instructors to support such classes) to ensure adequate staffing in light of the competitive environment for nuclear professionals.

SFHHA disagreed and argued that the Company had already increased its staffing levels in recent years. Witness Kollen stated that the Company proposed an increase in nuclear staffing of 270 employees due primarily to employee attrition and training requirements. He said the Company cited this as one reason for the proposed $37.298 million in excess over the benchmark level proposed for nuclear production on MFR Schedule C-41.

SFHHA witness Kollen also noted that in response to discovery, the single largest reason for exceeding the benchmark identified by the Company was an increase in payroll costs to reflect a significant increase in staffing levels. The Company quantified the payroll expense effect of adding these employees at $18.5 million for the test year compared to 2008. Witness Kollen explained that the Company cited its apprenticeship program and operations training as the primary reasons for the proposed increases in staffing levels in the test year compared to year end 2008.

According to SFHHA witness Kollen, the Company had been systematically reducing nuclear staffing since September 2008. Witness Kollen stated that ". . . the Company's nuclear staffing peaked in September 2008 and had been steadily declining each month since then." In addition, SFHHA witness Kollen stated that the Company's proposed increase in staffing levels was inconsistent with the significant capital investments the Company has made to improve the performance at its nuclear facilities that should reduce staffing.

SFHHA witness Kollen recommended ". . . that the Commission reduce the Company's nuclear production O&M expense by $21.852 million to eliminate the Company's request for increased staffing . . ." This amount consisted of an $18.5 million reduction in O&M expense, a $1.194 million reduction in payroll taxes, and a $2.158 million reduction in employee fringe benefits.

FPL witness Stall testified in rebuttal that the 270 head count increase referred to by witness Kollen included 129 positions supporting non-O&M activities such as uprate, capacity clause, and affiliate support. . . . The O&M costs forecasted in the 2010 test year did not include costs associated with these non-base O&M positions."

FPL witness Stall went on to explain that "due to the specialized nature of requirements for nuclear experience, it was imperative that an experienced nuclear operator train its employees." In addition to the 8-9 years to develop a senior reactor operator, witness Stall added that other positions can take 1-3 years to train. He pointed out that in such a lengthy program, there is a fair amount of attrition along the way. "Incremental staffing is needed to assure that we have sufficient experienced nuclear operations personnel."

FPL witness Stall testified that "[c]laims that FPL is reducing nuclear staffing are not correct. FPL is hiring today to fill critical positions to ensure the safe and reliable operation of our nuclear plants."

FPL witness Stall explained that "the long-term capital investments provide improvements in long-term plant reliability and do not offset the need for plant staff." He stated that these investments do result in fuel savings and many of the capital investments were in response to the Nuclear Regulatory Commission (NRC) requirements.

SFHHA witness Kollen's recommendation to eliminate nuclear staffing cost was based on 270 full time positions. Kollen failed to recognize that 129 of these positions had no effect on FPL's 2010 test year expense, because the 129 position were supporting non-O&M activities such as uprate, capacity clause, and affiliate support.

The Company presented persuasive testimony that it is in an active hiring mode for its nuclear business unit and that positions are indeed needed. The Company made it clear that there is a national shortage of qualified nuclear power plant staff, that there is a long training period to qualify new staff, and that changes to NRC requirements have resulted in an increase in the number of staff required to run and maintain a nuclear power plant.

Based on the foregoing, the Company has met its burden with respect to the number of additional employees required for the 2010 test year for its nuclear production staffing.

Salaries and Employee Benefits

FPL requested $765,261,494 to be included in O&M expenses for salaries and employee benefits. Based upon our discussion and conclusions below, we find that FPL's request is unreasonable and inappropriate, and thus reduce FPL's request by $49,510,136. As reduced in this Order, we find that FPL's O&M expense for salaries and employee benefits is reasonable.

Part of FPL's petition to increase rates included the recovery of incentive compensation for its employees, both executive and non-executive. During the proceeding, we conducted discovery and cross-examined several witnesses to evaluate the prudence of these projected expenses, as well as the prudence of the overall amount of salaries and benefits included in O&M expenses. In our efforts to evaluate the employee compensation expenses, we obtained information regarding compensation amounts, including bonus and overtime pay for certain highly-compensated employees (for purposes of this Order, highly compensated employees are those receiving $165,000 or more annually). Because of disputes between this Commission and the Company regarding the application of the public records law to employee compensation information, we had difficulty in obtaining the detailed information we sought to help us evaluate this O&M expense which FPL proposed to charge to ratepayers. While we did receive the requested employee compensation information, the information received was claimed confidential by FPL and its employees, thus making cross-examination and discussion cumbersome.

Nevertheless, we learned that FPL's proposed O&M expense budget for employee compensation for the 2010 test year was $765,261,494. Of that amount, $48,471,915 was to be paid to FPL executive employees as an incentive program. The term executive(s) as defined by FPL for use in this rate case referred to 42 employees that are officers of FPL, FPL Group, or one of its affiliates. The executive incentive compensation did not include the additional amounts paid to executives for base pay, lump sum pay or other pay. FPL's proposed executive incentive compensation represented 4.5 percent of FPL's proposed gross pay for 2010. At the hearing, FPL reduced its amount of proposed executive incentive compensation to $16,457,087 which is 2.25 percent of FPL's proposed gross pay for 2010.

FPL provided its executive incentive compensation program in response to an interrogatory request of the AG. OPC provided a copy of that response as Exhibit SB-15 for our review. Witness Brown listed the types of factors considered in determining whether an employee merits a reward under the incentive program. Those factors primarily relate to shareholder value and improving FPL's financial position. In fact, OPC witness Brown testified that pursuant to FPL's proxy the primary objective for FPL Group's executives is to support the creation of long-term shareholder value. Furthermore, the record reflects that FPL Group's goals for long-term incentive programs were to "promote the identity of interests between shareholders of FPL Group and employees of FPL Group and its subsidiaries by encouraging and creating significant ownership of FPL Group common stock by officers and other salaried employees of FPL Group and its subsidiaries . . ." Witness Brown concluded that this incentive program

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caused her concern in three areas: 1) that while the incentive compensation program was tied to increasing shareholder value, shareholders do not share in the costs of the incentive program, 2) that while FPL says it is concerned about the state of the economy and its effect on its customers, the executive incentive compensation program shields FPL's executive employees from the negative impact of the current economy and allows those employees to continue receiving "gold plated" compensation at ratepayers expense, and that 3) the proposed executive compensation assumes attainment of performance at levels higher than the objectives.

Witness Brown testified that in 2008, FPL gave the financial matrix a weighted 50 percent in calculating the corporate performance factor for its named executives. The other 50 percent of the corporate performance factor, although based on operation factors, also included financial performance measures. The CEO factor of the performance factor was not disclosed to OPC but witness Brown testified that the CEO factor has historically been based on financial performance. We concur with witness Brown that the executive incentive program is tied to shareholder value. But we disagree with witness Brown's conclusion that only 50 percent of the costs should be born by shareholders while the remaining 50 percent should be included as an O&M expense in this rate case. We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder value. We find that the executive incentive compensation program is designed to place the interests of executives in the same light as that of shareholders, thus creating incentive to increase the value of FPL Group's shares. Because these programs are designed for the benefit of shareholders, those costs shall be borne exclusively by shareholders.

We also concur with Witness Brown that while FPL expressed its concern with the effect of the economy on its ratepayers, its proposed executive incentive compensation program is designed to shield FPL Groups shareholders from the negative impact of the current economy. For instance, if the company does not meet its financial performance targets, the incentive compensation payments can be reduced while the shareholders retain the revenues paid by ratepayers for those incentive compensation programs. If the Company exceeds its targets, shareholders will receive the benefits of exceeding financial targets. Ratepayers will not receive those benefits.

We note that several witnesses provided us with comparative compensation information, comparing FPL employees with the market. Witness Brown testified that Watson Wyatt, one of the human resource consulting firms utilized by FPL, took a survey of large companies to understand what effect the economy was having on other executive programs. Witness Brown testified that the results of Watson Wyatt's study was published and that the study concluded that "more than half of respondents have frozen executive salaries, ten percent have reduced executive salaries, and annual incentive plans are declining." Furthermore, in response to discovery requests, FPL provided a presentation which indicated that at least half to about three-fourths of responding companies were reducing salary spending and merit pay increases or were contemplating salary freezes due to the recent economic situations or cost pressures.

Contrary to the indications of a slowing economy, FPL proposed at a minimum, to maintain or in some cases increase its O&M expenses over that provided in 2008. This

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requested increase in compensation is despite FPL's own testimony reflecting reductions in sales and higher bad debt attributable to the bad economy. While most competitive businesses would seek avenues of decreasing costs in response to economic conditions, FPL is actually requesting an increase in its compensation costs.

An example of an area in which FPL's request for increased compensation is unreasonable in light of the current economy is in the number of highly compensated support group (non-operational) positions which appear to us to be redundant. FPL expressed a need to protect its nuclear division from poaching. We requested and received compensation information, in confidential format, for employees earning above $165,000 annually. Upon review of the actual amounts proposed to be paid to employees, FPL's reasoning was not supported. There were several director and vice-presidential positions in support group positions which appear to reflect a larger portion of the bonus and pay compensation than did the nuclear operational employees. In fact, of the employees listed in discovery responses as receiving more than $165,000 annually, only 66 percent of them were in the nuclear division. Moreover, we identified several positions in the highly compensated support group functions that appear redundant. While we believe that much of the compensation paid for those positions may reflect unreasonable and imprudent compensation, we find that at a minimum $300,000 of that compensation is unreasonable and inappropriate and thus disallow $300,000.

While we found that the executive incentive compensation was designed to benefit the value of shares, we are hesitant to conclude that one hundred percent of the non-executive incentive compensation benefited only shareholders. Accordingly, we concur with OPC witness Brown that 50 percent of the non-executive incentive compensation, after adjusting the payout ratio for stock-based compensation from 1.3 times to the target to 1.0 times the target, shall be excluded from O&M expense as unreasonable. The proposed reduction to limit the incentive remaining, after the adjustment for the payout ratio, to 50 percent was a reduction in jurisdictional O&M expenses of $3,538,246 for the 2010 test year. The total decrease in jurisdictional O&M expenses due to the non-executive incentive compensation reductions was $5,661,193 for the 2010 test year.

We calculated the employee incentive compensation based upon the target level of 1.0 percent as explained by OPC. OPC witness Brown explained that FPL had used a projected payout level of 1.4 times the target level for executives and 1.3 times the target level for non-executives. She stated:

> I am first recommending that the Commission reduce the levels of the executive Annual Incentive Compensation and Long-Term Incentive Pay to reflect a target payout ratio of one (1) times the target compensation. This is a reasonable assumption to make for a future test year, particularly a year in which the Company has represented that its return on equity will drop to 4.67% without the requested rate increase.

We agree that the payout ratio for the incentive awards shall be reduced to the target level and not set at 1.3 or 1.4 times the target. If the Company is consistently achieving 30 to 40 percent above the baseline year after year, then the incentive payments have essentially become base salary. Exhibit 242 showed the reductions in incentive compensation to executives proposed by OPC witness Brown. The proposed adjustment to reduce the payout ratios for executive incentive compensation to 1.0 resulted in a reduction in jurisdictional O&M expenses of $12,226,189 for the 2010 test year. OPC witness Brown recommended similar adjustments for FPL's non-executive incentive compensation. The proposed reduction to lower the payout ratio from 1.3 times the target to an amount equal to the target is a reduction in jurisdictional O&M expenses of $2,122,947 for the 2010 test year.

Finally, FPL proposed adjustments to its original filing. Among those adjustments, it removed executive bonuses in the amount of $757,282 for the 2010 test year. We approve this adjustment.

Based on the foregoing, we reduce FPL's O&M expenses by $757,282 to reflect FPL's concession to eliminate the executive raises. We reduce FPL's O&M expenses by $12,226,189 to reduce the payout ratio for executive incentive compensation from 1.4 times the target level to 1.0 times the target level. We reduce FPL's O&M expenses by $30,565,472, to reflect a 100 percent reduction in executive incentive compensation. We reduce O&M expense by $2,122,947 to reflect the change in the payout ratio for non-executive incentive compensation from 1.3 times the target level to 1.0 times the target level. We reduce O&M expenses by $3,538,246 to limit non-executive incentive compensation remaining after the adjustment for the payout ration to 50 percent. We reduce O&M expenses by $300,000 to reflect our determination that there are redundant highly compensated non-operational positions. The total reduction of FPL's O&M expenses for salaries and benefits is $49,510,136.

Pension Expense

We were asked to determine if any adjustments should be made to net operating income for pension expenses. We analyzed and reviewed the MFRs, discovery responses, testimony, and cross examination and determined that there shall be no adjustments for pension expense, except for the adjustments made by FPL in Exhibits 481 and 511. The pension amounts were estimated from an actuarial calculation for the 2010 FPL Group plan costs and related obligations using consistent methodologies and reasonable, supportable assumptions. We decline to make any additional adjustments for pension expense.

Environmental Insurance Refund

We were asked to determine if a test year adjustment was necessary to reflect FPL's receipt of an environmental insurance refund in 2008. OPC proposed a decrease in O&M expense to recognize FPL's receipt in 2008 of a refund for environmental insurance it had previously purchased. OPC witness Brown testified that FPL's rates included the costs for property insurance and, as such, any refunds should be provided to ratepayers. The adjustment proposed by OPC witness Brown, based on a five year amortization of the insurance refund, was a decrease in jurisdictional O&M expense of $8,685,682 for the 2010 test year and a decrease in jurisdictional O&M expense of $8,685,656 in the 2011 subsequent test year. The adjustment would also increase jurisdictional rate base by $39,085,569 for the 2010 test year.

The policy that created the refund was purchased in 1998, a non-base rate setting year, and was never included in the Company's Environmental Cost Recovery Clause (ECRC). This is not an accounting gain but an out-of-period expense reduction that was recorded in 2008, and was related to the period of 1998 through 2007. The expense associated with the purchase and the reduction in expense associated with the refund was properly reflected in the Company's surveillance reports.

Based on the foregoing, we decline to make any further adjustments for the environmental insurance refund in 2008.

Department of Energy Settlement

We were asked to address the treatment of an expected monetary settlement and whether it should be incorporated into FPL's books in the 2010 projected test year. The monetary settlement was the result of a lawsuit FPL filed against the United States Department of Energy (DOE) concerning the disposal of spent nuclear fuel. Two exhibits sponsored by FPL witness Kim Ousdahl summarized the test year adjustment for the DOE settlement funds FPL made for 2010.

FPL witness Ousdahl testified that FPL should make an updated adjustment to its 2010 Test Year revenue requirements to reflect new information from the DOE. She testified that:

> FPL's 2010 Test Year jurisdictional revenue requirements should be adjusted by \$(6.9) million, representing the NO1 impact and \$(3.1) million, representing the rate base impact. These adjustments are based on the amount of capital and operations and maintenance expenses the Company has identified in its 2010 forecast that are expected to be reimbursed by the DOE, and apply the same recovery assumptions from FPL's settlement agreement with the DOE entered into on March 31, 2009 resolving FPL's damages incurred prior to 2008. FPL has calculated these adjustments to its 2010 revenue requirements associated with the expected reimbursement, and has included them as Items 3 and 4 of Exhibit KO-16 [358].

FPL witness Stall explained that FPL will incur capital and O&M expenditures to manage the DOE's failure to begin accepting spent nuclear fuel for disposal as required by law. He further stated:

> On-site storage capacity for spent fuel in the spent fuel pools is limited. As existing capacity is utilized, alternative methods for storing the spent fuel are required. Alternative storage is required as a prudent operational measure whenever the spent fuel pools can no longer accommodate a full-core offload. Maintaining a full-core offload capability is a prudent measure in the event that all of an entire core of reactor fuel must be offloaded to accomplish emergent repairs to the reactor.

We find that the test year adjustments presented in hearing Exhibit 358 and detailed in Exhibit 477 are appropriate to reflect the expected settlement received from the Department of

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Energy. Accordingly, FPL's O&M expenses, depreciation expense and taxes other than income taxes are reduced by $6,084,000, $747,000, and $109,000, respectively, for the 2010 test year. Plant in service, depreciation reserve and CWIP are reduced by $25,866,000, $252,000, and $828,000, respectively, for the 2010 test year.

Transactions with affiliated companies

OPC witness Dismukes testified to the importance of our examining transactions between FPL and its affiliates. We reviewed the testimony and exhibits from FPL and OPC regarding FPL's transactions with its affiliates. Upon completion of our review we determined that for certain affiliate transactions, we needed additional information.

FPL witness Ousdahl provided an overview regarding the methods FPL used to charge costs to its affiliates including FPL's New England Division (FPL-NED). FPL-NED is a division of FPL, and not a separate affiliate. Witness Ousdahl described the controls in place to ensure that FPL's retail customers did not subsidize FPL's affiliates.

Witness Ousdahl testified that there are three ways that FPL charges costs of shared activities to its affiliates. Those are direct charges, service fees, and affiliate management fees (AMF). Direct charges are those costs of FPL resources used exclusively to provide service for the benefit of the affiliate company and are directly charged to that affiliate. Service fees are costs for ongoing services provided to one or more affiliates of FPL. AMF are costs associated with corporate staff infrastructure and governance costs that benefit both FPL and all the affiliates and are categorized into specific cost pools.

Regarding the third category, AMF, where distinct cost drivers may be determined, Witness Ousdahl stated that:

> . . . the cost of ongoing services shared jointly to support utility and affiliate operations are allocated using specific factors. Examples of these cost pools include corporate systems applications, support for computer mainframe operations, benefit programs, and corporate security. The drivers to allocate these costs are carefully selected in order to accurately allocate costs. Examples of commonly used drivers include number of personal computers, number of transactions, headcount and square footage . . .

Concerning the cost pools associated with the AMF, which do not have distinct cost drivers, Witness Ousdahl explained that these cost pools are:

> . . . allocated using the Massachusetts Formula, a methodology widely accepted by utility regulators as a fair and reasonable way to allocate common costs among affiliates. The Massachusetts Formula has three components: property, plant and equipment, revenue and payroll. . . . The use of a calculated average of property, plant and equipment, revenue and payroll appropriately considers the various factors affecting the use of common services. Examples of cost pools that do not

> have a specific driver include budgeting, and planning, external financial reporting, corporate communications, mail services, and shareholder services.

Witness Dismukes identified concerns with different FPL methodologies for charging its affiliates. She made recommendations for most of those concerns. Witness Dismukes argued that the Company's data was stale and needed updating. She felt that the factors inaccurately reflected the amounts that should be allocated to FPL. Witness Dismukes also testified that there were problems with FPL's use of the Massachusetts Formula. Witness Dismukes expressed concern regarding certain transactions between FPL and its affiliate FPLES. She also testified that FiberNet's charges to FPL overstated the cost of capital charged by FiberNet to FPL for FiberNet's services. Witness Dismukes also addressed her concerns regarding power monitor regulations.

<u>Updates to Specific Drivers</u>

Concerning the problem that she identified with the Company's use of allocation factors for specific drivers that need to be updated with more current data, OPC witness Dismukes recommended the following:

> First, to overcome the problem associated with the Company's use of stale allocation factors, I recommend that the Commission update the specific drivers to reflect the most recent information available. With respect to the Power Generation Division Fee I recommend that the Commission update the installed megawatts using the Company's disclosures in its 2008 annual report and testimony filed in this proceeding. . . . Second, . . . in instances where the Company did not project an increase for the projected test years, I recommend that the Commission increase the allocation drivers based upon recent growth. . . . I recommend that the Commission reduce test year expenses by $2.3 million in 2010 . . . .

FPL witness Ousdahl responded to the concerns raised about "stale" drivers for certain allocation factors in her rebuttal testimony. Witness Ousdahl stated that:

> Ms. Dismukes has made the incorrect assumption that all of the specific drivers used in the AMF will increase over time. To address Ms. Dismukes' concern that the drivers were not current, FPL has provided drivers updated in the first quarter of this year as a part of its normal billing process to compare to those included in the rate filing. The drivers used for the test year forecasts and the new drivers are shown on Exhibit [356] KO-14. The minor fluctuations between the two sets of drivers indicate that many of the new drivers actually decreased.

FPL witness Ousdahl also addressed the update to the installed megawatts:

> FPL again used the most current information available at the time to develop the allocation factors. Contrary to Ms. Dismukes' testimony, this information already included 1,219 MW related to FPL's West County Energy Unit 1 and 864 MW of

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> wind capacity for NextEra for 2009. FPL updated MW information used for these calculations as of the second quarter of 2009. Exhibit 357 shows the current forecasted relative MW of capacity, which are minimally different from those included in the filing.

OPC's recommended adjustment for stale drivers, used for specific drivers of shared affiliate costs, assumes that allocation drivers to affiliates of FPL will always increase. This is not necessarily correct because the percentages representing the drivers are the relative size of one affiliate to another. The constant increase of allocation drivers to affiliates of FPL assumes that the affiliates are always going to grow faster than FPL itself. For example, the specific driver based on the number of personal computers owned by FPL and each affiliate, produces a percentage to allocate certain shared costs. The number of personal computers is not necessarily going to grow faster at the affiliates of FPL than FPL itself. If the specific drivers are growing faster for the affiliates of FPL versus FPL itself, then it would seem that the cost pool to support the growth in the affiliates would also need to be increased to account for the additional work load.

We find that the most current factors shall be used in projections, as long as there they are representative of the future and that no changes of an unusual nature have occurred from one measurement period to the next. However, this does not mean that there will always be an increase in the factors over an earlier period. FPL filed the latest available drivers in Exhibit 356. FPL also filed the latest relative MW capacity between NextEra and FPL available. These exhibits showed that there was not a material change in the specific drivers in the latest quarter of data available and that some drivers went down. Accordingly, we do not find that OPC's recommended adjustment to reduce expenses by $2.3 million for the 2010 test year is appropriate, and we decline to do so.

Massachusetts Formula:

OPC Witness Dismukes recommended two adjustments concerning problems she perceived with FPL's use of the Massachusetts Formula. The first problem she addressed, FPL's failure to update the components used in the calculation of the Massachusetts Formula, would only have affected the revenue requirements for the 2011 test year. Since we declined to approve a 2011 test year, we need not address this issue.

OPC witness Dismukes' other perceived problem with the Massachusetts Formula was that it did not account for the benefits that the non-regulated affiliates received from their association with FPL and FPL Group. Witness Dismukes stated that the Massachusetts Formula implicitly assumed that the larger the affiliate, the greater its received benefit from shared services. She recommended the following:

> To address the problems associated with the size-based nature of the allocation factor and the significant benefits the non-regulated affiliates derive from being associated with FPL and FPL Group, I recommend that the Commission distribute shared executive costs of the FPL Group between FPL and the non-regulated

> affiliates with 50% assigned to each. . . . As shown on Exhibit [201] KHD-11, the changes that I recommend concerning the allocation of the AMF reduce charges to the Company in the projected years by $7.9 million for 2010 . . . .

FPL witness Ousdahl addressed OPC witness Dismukes' concerns with the Massachusetts Formula's failure to reflect the benefits that FPL affiliates received from the shared services:

> The objective of performing cost allocations to affiliates is to recover the cost of the shared services that the affiliates use in order to ensure that FPL's customers are not paying any costs that would result in a subsidy to those affiliates. . . . Ms. Dismukes ignores the benefit that FPL and its customers receive from affiliate relationships. FPL has greater access to high quality resources without having to incur the full cost thereof. . . . While I agree that the Massachusetts Formula results in larger allocations for larger companies, this result is entirely appropriate. . . . To the extent we can identify a causal relationship between activities and support services, specific drivers are used to allocate costs. All of these allocations result in the larger companies receiving a larger share of costs. When a similar result occurs because of the application of the Massachusetts Formula for truly un-attributable costs, it neither is unexpected nor inappropriate. It is for this very reason the Massachusetts Formula has been so widely accepted in the utility industry as well as by this Commission. No adjustment is necessary to the Massachusetts formula results.

In her summary, Witness Ousdahl stated:

> Ms. Dismukes' recommended adjustments are based on inappropriate trending and 50/50 allocations, and ignore the use of specific drivers and the long standing Massachusetts formula employed by the Company. Her suggested use of trending is clearly inappropriate. She is forecasting the historic trajectory of the growth in affiliates into the 2010 and 2011 timeframe, which quite ignores the constraints faced today in the capital markets which will make it impossible for historical rates of growth to continue.

OPC's second proposed adjustment to the Massachusetts Formula was made to better reflect the benefits that the affiliates receive from their association with FPL and FPL Group. OPC recommended that the Massachusetts Formula be changed to distribute the shared executive costs of the FPL Group between FPL and the affiliates by assigning 50 percent to each. While we are not required to adhere to the Massachusetts Formula without question or examination of its results, the Massachusetts Formula was designed to fairly distribute un-attributable costs to insure that a regulated company does not subsidize its affiliates. This is why the Massachusetts Formula has been widely accepted in the utility industry and accepted by us in the past. We have reviewed the testimony and do not find a clear empirical reason to change the use of the Massachusetts Formula in this docket. Accordingly, we decline to adjust the Company's forecast based on the Massachusetts Formula, proposed by OPC.

FPL Energy Services:

Witness Dismukes also had concerns about the transactions between FPL Energy Services (FPLES) and FPL. FPLES is an affiliate of FPL that provides energy-related products and services and is not regulated by us. Witness Dismukes did not believe that the sale of FPL's natural gas contracts was at a reasonable price. She stated that she "developed [her] recommended adjustment by averaging the gross margin earned from these contracts over the five years preceding the sale." Her proposed adjustment was to recognize a gain on the sale of $1,090,753 for both the 2010 and 2011 test year.

FPL witness Santos testified concerning the January 1, 2006, sale of the natural gas business of FPL to FPLES. Witness Santos stated:

> As stated earlier, the matter related to the sale of the FPL gas contracts to FPLES was resolved per the Stipulation and Settlement Agreement. Since 2006, FPLES has been responsible for all activities related to the Gas Business and has assumed all related risk. FPL has not been involved in this business since that time. As such, the gross margins realized from the Gas Business are unrelated to FPL and its rate payers. No adjustment is necessary contrary to Ms. Dismukes' recommendation.

The gains or losses on the sale of the gas contracts to FPLES by FPL were completely explored and debated in the Company's last rate case, including direct and rebuttal testimony. That case was settled and we approved the stipulation in the 2005 Settlement Order.[65] The order stated "This Stipulation and Settlement will resolve all matters in these Dockets . . ."

The second concern over transactions between FPL and FPLES was discussed by Witness Dismukes:

> Clearly, if FPL is billing on its electric bills for services that FLPES provides to FPL's residential, commercial, and governmental customers, FPLES should compensate FPL for the use of its personnel, billing systems, collection systems, postage, paper and any other costs associated with billing the customer. OPC has issued additional discovery on these matters and intends to present additional information to the Commission on the subject.

FPL witness Santos also testified concerning FPL's billing on its electric bills for services of FPLES, stating that, "[f]or those FPLES programs that utilize the FPL bill, FPLES compensates FPL accordingly for billing, collection and any other related costs.

We share the concerns of witness Dismukes regarding FPLES's use of FPL's services for the benefit of FPLES programs. FPLES offers products to FPL's customers through FPL's bill inserts. FPL processes the cost of that on its bill. We are concerned whether there is cross-

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[65] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.

subsidization and whether it is really a level playing field to the extent competitors want to offer the same products as FPLES. Furthermore, we are concerned that products offered in this manner cause customer confusion; in addition we heard testimony regarding the limitations of these products. Accordingly, to explore our concerns, we find it appropriate to open a separate docket to investigate the relationship of and the appropriateness of FPLES offering products to FPL consumers.

FiberNet:

OPC witness Dismukes proposed lowering the charges from FiberNet to FPL by reducing the rate of return on FiberNet's assets. Witness Dismukes recommended lowering the return charged by FiberNet to that suggested by OPC witness Woolridge. This adjustment would reduce O&M expenses by $1,182,224 for the 2010 test year. Concerning the costs charged to FPL by FiberNet, an affiliate of FPL, OPC witness Dismukes testified:

> With respect to costs allocated from FiberNet, for the projected test year costs were allocated using fiber miles, fiber capacity, and DS3 capacity. I am recommending one modification to the methodology employed to allocate these costs to FPL. As shown on Exhibit 202, the allocation of costs to FPL is based upon the assets owned by FiberNet. A large portion of the costs allocated to FPL are based upon the return on the assets used by FPL. In developing the amount to charge FPL, the Company used a return on investment . . . I have modified this return to be consistent with the pre-tax overall cost of capital recommended by Dr. Woolridge. The Commission should reject the Company's request to use a rate of return that is substantially in excess of FPL's allowed rate of return and utilize the rate of return recommended by Mr. Woolridge. As shown on this exhibit, this change results in an estimated reduction to charges for the years 2010 and 2011 of $1,182,224 [each year].

FPL witness Avera's rebuttal Exhibit 363 (Rebuttal to Technical Arguments) stated that:

> . . . the risks and cost of capital for telecommunications services is generally regarded as higher than for electric utility services, particularly for competitive local exchange companies such as FiberNet. . . . A review of Exhibit JRW-18 reveals that the average beta for the Telecommunications Services industry was 1.43, versus the 0.88 beta value cited by Dr. Woolridge for the electric utility industry and a beta of 1.00 for the overall market.

In other words, FPL witness Avera believed this comparison indicated that the risks associated with FiberNet were higher than FPL. Witness Avera concluded that OPC witness Woolridge's recommended overall rate of return for FPL was entirely unrelated to the services provided by FiberNet.

FPL could own its own telecommunications equipment that would be used strictly for its own use. If this were the case, the assets would be a part of the Company's rate base and it would be allowed to earn the same return as the rest of its rate base assets. We find that FiberNet has higher risk as a separate affiliate, and that the ratepayers shall not be required to pay for this additional risk. The return payable to FiberNet from FPL ratepayers shall be that permitted to be earned by FPL. This adjustment decreases O&M expenses by $1,182,224.

Power Monitoring Revenue:

OPC recommended increasing miscellaneous revenue by $236,336 for the 2010 test year. These increases were to certain revenues excluded from revenue due to a mislabeling. FPL witness Ousdahl stated that the data was mislabeled in an informal discovery response as power monitoring revenues, and should have been labeled as regulation service revenues. She went on to say:

> This description change is supported by FPL's response to OPC's First Set of Interrogatories Question No. 55 where the same amounts are shown for 2006, 2007 and 2008 with a description of Regulation Service Revenues. Even though FPL misidentified the account description, it does not impact the amounts forecasted for Power Monitoring revenues, which are properly reflected in FPL's MFR's.

We find that this adjustment was unnecessary and that the revenues associated with this item were correctly shown in the Company's MFRs.

Forecast Updates:

FPL witness Ousdahl sponsored Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified appropriate adjustments to the Company's filing. Exhibit 358 summarized the adjustments to rate base, net operating income, and capital structure that FPL proposed to its original filing.

Item 5 of Exhibit 358 showed FPL's proposed adjustment due to an overstatement of affiliate payroll loadings. According to FPL, affiliate payroll loading was overstated because it was not based on the final payroll forecast from the business units. Item 5 resulted in an adjustment to decrease O&M expense and taxes other than income taxes by $3,373,000 for the 2010 test year. The forecast updates result in an adjustment to decrease O&M expense and taxes other than income taxes by $3,592,000.

Conclusion

Based on the foregoing, we find that: 1) the Company's proposed adjustment for the forecast data shall be accepted, and that O&M expense and taxes other than income taxes shall be decreased by $3,373,000; 2) that no adjustment shall be made for stale allocation drivers; 3) that no adjustment shall be made for the Massachusetts Formula; 4) that no adjustment shall be made for FPL Energy Services; 5) that adjustment to the charges from FiberNet to FPL shall be made resulting in an O&M expense reduction of $1,182,224 for the 2010 test year; 6) that no adjustment shall be made for the power monitoring revenue; and 7) that a generic docket shall be opened to investigate the relationship of and the appropriateness of FPLES offering certain products to FPL consumers. The total reduction in this docket for O&M expense and taxes other than income taxes is $4,774,224 for affiliate transactions.

ATTACHMENT B

Gains on sale of utility assets

We were asked to determine if an adjustment was necessary to reflect the gains on sale of utility assets sold to FPL's non-regulated affiliates. OPC witness Dismukes sponsored Exhibit 204, which showed that during 2007 and 2008 the Company sold several assets to its affiliates which resulted in a gain on sale. As shown on Exhibit 204, during 2007, the Company sold 15 assets which resulted in a total gain of $4.6 million. The largest gain resulted from the sale of a combustion turbine rotor to FPL Group, Inc. which resulted in a gain of $4.5 million. During 2008, the Company sold 14 assets which resulted in a gain of $877,706. The largest gain, $872,974, related to a transformer sold to Calhoun Company I, LLC. The total gains for both years amounted to $5.5 million.

According to OPC witness Dismukes, we have had several cases in which we ruled on the gain or loss on the sale of a utility asset. Witness Dismukes cited our recent decision regarding transaction and transition costs for Florida City Gas. Witness Dismukes recommended that we pass the gains on to customers and amortize them over five years. Her adjustment, shown in Exhibit 204, resulted in an increase in net operating income of $1.1 million for the 2010 test year.

FPL witness Ousdahl explained that our orders as cited by OPC witness Dismukes referred to transactions for the sale of entire gas systems and the sale of land. Witness Ousdahl stated:

> Ms. Dismukes cites FPSC Docket No. 060657-GU, Order No. PSC-07-0913-PAA-GU, issued November 7, 2007. This order relates to the sale of an entire gas plant. The order also includes an embedded reference to FPL Docket No. 830465-EI, Order No. 13537, issued July 24, 1984. This order discusses regulatory treatment for a gain on sale of land. These transactions represent sales of facilities and land, and Commission policy for the amortization of gains or losses on the sale of these entire systems and land parcels would be appropriate. However, Ms. Dismukes attempts to apply this Commission policy to FPL's sale of retirement units which were transacted in 2007 and 2008. Gains and losses that arise from the sale or interim retirement of retirement units of a utility are deferred to the balance sheet and accounted for in future depreciation. Specifically, for the FPL transactions analyzed by Ms. Dismukes in 2007 and 2008, when the FPL assets were sold, the original cost of the asset was debited to account 108 and credited to account 101. Then, as required by USOA and FPSC rules and practice, FPL recorded a debit to cash and a credit to account 108 for the sales proceeds at market in accordance with FPSC and FERC guidelines for retirement of plant in service retirement units. The customers will benefit from these gains through reduced return and decreased depreciation expense as is the requirement of the USOA and regulatory accounting practice for electric utilities.

We find that FPL applied the correct interpretation to the Uniform System of Accounts and applied the correct accounting to the gains referred to in this issue. The treatment

ATTACHMENT B

recommended by OPC is appropriate for the sale of entire systems and land. Accordingly, no adjustment is necessary for gains on sale of utility assets sold to FPL's non-regulated affiliates.

Transfer of the FPL-NED Assets

We were asked to determine if we should order FPL to report the future transfer of the FPL-NED assets from FPL to a separate company under FPL Group Capital. OPC witness Dismukes made recommendations for safeguarding ratepayers from any risks related to the transfer of FPL-NED assets to a separate company under FPL Group Capital. Witness Dismukes testified that:

> The Commission should ensure that at the time of the transfer to this new company, the assets are transferred at the higher of cost or market as required by its affiliate transaction rules. In addition, the Commission should order that an independent appraisal be prepared as to the fair market value of these assets, as required by its rules on affiliate transactions.

FPL witness Ousdahl stated that the provision of our affiliate Rule 25-6.1351-3(d), F.A.C., does not apply to the situation of FPL-NED. Witness Ousdahl testified that:

> Section 3(d) of the affiliate rule applies the requirement that assets be transferred at the higher of net book value or market when an asset used in regulated operations is transferred from a utility to a nonregulated affiliate. This rule does not apply because FPL-NED assets have never been used in operation in any Florida retail jurisdiction regulated by the FPSC.

We agree with OPC. We direct FPL to notify us at the time FPL-NED assets are transferred to a separate company. At that time, FPL shall provide us with an independent appraisal as to the fair market value of the assets. We find that Rule 25-6.1351-3(d), F.A.C., applies to this transaction and that the assets transferred shall be at the higher of cost or market as required by our rules.

Storm Damage Reserve

FPL proposed an annual storm damage accrual of $150,000,000 per year with a target reserve level of $650,000,000. OPC, AG, FIPUG, FRF, and SFHHA disagreed with FPL and suggested that there be no accrual of storm damage reserve and that the target level of the reserve be $200,000,000, which has already been funded. We were asked to determine whether to adjust FPL's revenues to exclude all or a portion of FPL's proposed accrual.

FPL witness Pimentel described what he believed to be the key policy considerations underlying the storm cost recovery framework, as articulated in Orders Nos. PSC-93-0918-FOF-EI, PSC-95-0264-FOF-EI, and PSC-95-1588-FOF-EI. According to witness Pimentel, the key principles are:

> First, storm restoration is a cost of providing electric service in Florida and is therefore, properly recoverable through the rates and charges of the Company.

> While we cannot predict with certainty when storms will occur, we can predict with virtual certainty that tropical storms and hurricanes will affect our service territory and we will incur costs for restoring power. However, those costs are not reflected in the Company's base rates.
>
> Second, each "generation" of customers should contribute to the cost of storm restoration, even if no storm strikes in a particular year. Since storms will occur and only their timing is uncertain, the true cost of providing electric service should include an allowance for a level of restoration activity that approximates the expected annual storm costs.
>
> Third, "pre-funding" restoration costs sufficient to cover an extreme sub-period of storm activity (ie., building up a Reserve sufficient to cover virtually all storm restoration) is likely to be economically inefficient. Thus, some mechanism for recovery of the prudently incurred costs that exceed the Reserve is required.

FPL witness Pimentel went on to explain that since Hurricane Andrew, commercial insurance to cover storm cost has been unavailable. He described the framework he believes to be endorsed by us as consisting of three main parts: (1) an annual storm accrual; (2) a reserve adequate to accommodate most but not all storm years; and (3) a provision for utilities to seek recovery of costs that go beyond the reserve.

As a result of the 2004 storm season, costs incurred to restore electric service following Hurricanes Charley, Frances, and Jeanne, totaled $890 million (net of insurance proceeds), completely depleting FPL's Reserve. In Order No. PSC-05-0937-FOF-EI,[66] we approved a surcharge of $1.65 (per 1,000 kWh residential bill) which was intended to eliminate the deficit in the reserve.

Witness Pimentel then explained what happened to the Company's storm reserve as a result of the 2005 storm season. He testified that,

> In 2005, another very active storm season, four Hurricanes inflicted damage on FPL's system. Restoration costs associated with Hurricanes Dennis, Katrina, Rita and Wilma increased the Reserve deficiency by approximately $816 million, leaving a deficit balance in the Reserve in excess of $1.1 billion. The Storm Restoration Surcharge was designed to recover approximately $300 million of that amount by February 2008, leaving approximately $800 million to he recovered through another means, as well as the question of how best to restore the Reserve to a reasonable level going forward.

Next FPL witness Pimentel addressed the effects of Order No. PSC-06-0464-FOF-EI[67] approving the issuance of bonds to finance storm restoration costs:

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[66] Order No. PSC-05-0937-FOF-E1, issued September 21, 2005, in Docket No. 041291-E1, <u>In re: Petition for Authority to Recover Prudently Incurred Storm Restoration Cost Related to the 2004 Storm Season that Exceed the Reserve balance, by Florida Power & Light Company</u>.
[67] Order No. PSC-06-0464-FOF-EI, issued May 30, 2006, in Docket No. 060038-EI, <u>In re: Petition for issuance of a storm recovery financing order, by Florida Power & Light Company</u>.

> The Commission approved the issuance of Bonds in the amount of up to $708 million, provided the initial average retail cents per kWh for the Bonds would not exceed the average retail cents per kWh for the Storm Restoration Surcharge which was then in effect. The proceeds from the issuance of Bonds authorized by this Financing Order were required to be used by FPL to finance the after-tax equivalent of the following amounts: (1) approximately $199 million in unrecovered 2004 storm-recovery costs as of July 31, 2006 (estimated); (2) approximately $736 million in 2005 unrecovered storm-recovery costs (estimated); (3) replenishment of FPL's Reserve to the level of $200 million; and (4) $11.4 million in financing costs (estimated) associated with the Bonds. To the extent there were differences between the actual and estimated balances for unrecovered 2004 and 2005 storm restoration costs and between the actual and estimated financing costs, the differences were to be reflected through an adjustment to the Reserve.

FPL witness Pimentel explained that FPL commissioned studies to calculate the annual amount of expected windstorm losses, as well as the expected value of the Reserve given various funding levels. The studies were prepared by and were sponsored by FPL witness Harris of ABS Consulting.

Witness Harris summarized the results of the Reserve Performance Analysis:

> Reserve performance can be viewed in terms of the expected balance of the reserve and the likelihood of insolvency occurring in any year of the five-year periods. Based on the simulated loss distributions, there is some likelihood of the reserve having a negative balance for each of the annual accrual levels analyzed. Higher accrual levels will result in a lower probability of the reserve having a negative balance, and will have a higher probability of a positive reserve balance at the end of the five-year simulation period.

Witness Harris was asked if FPL's selection of a $650 million target level for the reserve is adequate. He answered that "[b]ased on the current value of FPL's T&D assets, a reserve balance of $650 million would be adequate to cover uninsured losses during most, but not all, storm seasons." Witness Harris was asked for his conclusion with respect to the $150 million annual level of accrual selected by FPL.

> . . . My analysis indicates that, with an expected annual loss of $153.3 million, an annual accrual of $150 million and the ability to recover any negative reserve balances over a two-year period, the balance of the reserve at the end of five years would grow from the initial $215 million to an expected balance of $382 million. . . .

In asking whether the Company should be allowed the proposed annual accrual of $150 million with a target reserve of $650 million, OPC witness Brown answered no:

> While Mr. Pimentel notes some key policy considerations, the balancing of generational ratepayer interests is extremely important in this case. FPL's

> customers are currently facing tough economic times. FPL's requested storm damage accrual of $150 million a year is over 14% of FPL's requested 27% increase in base rates. While it is not reasonable or feasible for customers to pay for storm costs in the year of occurrence and thus requires customers over several generations to provide revenues to cover such costs, the Commission must also recognize that current ratepayers are already paying a substantial amount to cover past storms, as well as replenishment of the storm reserve fund to over $200 million. In 2010, FPL anticipates storm recovery revenues of $93.957 million. Generational sharing of costs does not require pre-funding and may result in deferred cost recovery or securitization such as the current securitized bonds covered by the storm recovery surcharges.

We have balanced the need to make certain that FPL will be able to reliably provide electricity to its customers in the event of storms, with the need to set fair, just and reasonable rates. We are aware that when storm costs occur, customers will be called upon to pay those costs, either through a reserve fund or through a surcharge. Yet we are very aware and very concerned with the current economic times. We have been made aware, through testimony, that customers have difficulty paying their bills, without our adding an additional burden that could be deferred. Furthermore, customers are already paying a surcharge for past storm costs. Allowing the Company to begin collecting an annual accrual, in addition to the existing surcharge could have the same effect as double surcharges in the future. We have previously supported the process of building a storm cost reserve, and as a result the Company has funded a storm reserve. This funded reserve bears interest. We note that there are provisions for the protection of utilities to allow them to seek recovery of prudently incurred storm costs that go beyond the reserve level. Because these mechanisms are in place to recover storm costs, we choose at this time, not to place this additional burden on the ratepayers. Accordingly, FPL's O&M expenses are decreased by $148,666,500.

Rate Case Expense

FPL requested recovery of rate case expense of $3,657,000 over a three year amortization period. While the total rate case expense of $3,657,000 was a fair estimate of what rate case expense would have been without the subsequent 2011 test year and GBRA request, we disagree with certain aspects of FPL's proposal.

FPL included $450,000 for overtime and or bonuses for salaried employees in its original total rate case expense filing. We have historically disallowed recovery of additional pay or bonuses as a part of rate case expense.[68] In Order No. PSC-08-0327-FOF-E1,[69] we stated "Salaried Overtime Pay for Extraordinary Work Load" shall be disallowed because these employees and managers are paid a salary, not an hourly wage. Salaried employees are usually expected to work the hours required to complete their job duties without extra compensation.

[68] See Order No. PSC-08-0327-FOF-E1, issued May 19, 2008 in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company.
[69] Id.

FPL requested that the unamortized balance of rate case expense be included in rate base. FPL witness Ousdahl stated that recovery of necessary rate case expenses was appropriate and has historically been included in the Company's revenue requirement. She testified that,

> Similar to FGPP cost recovery, the unamortized balance must be included in rate base in the Test Year in order to avoid an implicit disallowance. The Company has been prudent in limiting its incremental rate case expenses, while being mindful of the need to present and fully support its case in accordance with Commission requirements.

We do not agree with the Company that the unamortized balance of rate case expense should be included in rate base. Historically, the unamortized balance of rate case expense has been excluded from rate base to reflect a sharing of the rate case cost between the ratepayers and the shareholders.[70] Rate case expenses are recovered from ratepayers through the amortization process as a cost of doing business in a regulated environment. However, the unamortized balance of rate case expense has been excluded from rate base to reflect that an increase in rates is a benefit to the shareholders. The Company included $2,948,000 in working capital for the 2010 test year.

FPL requested that the rate case expense be amortized over three years. OPC suggested that recovery occur over 5 years. We shall permit rate case expense for FPL to be amortized over a four year period which is consistent with several of our recent decisions.[71] Four years is a more likely time period than three or five years for the Company's next filing.

Based on the foregoing, we reduce the Company's total rate case expense of $3,657,000, as originally filed, by the $450,000 for overtime and/or bonuses for salaried employees. Total rate case expense as adjusted is $3,207,000. Total rate case expense shall be amortized over a four year period at an amortization of $801,750 per year. The unamortized balance of rate case expense shall be excluded from working capital. We reduce rate case amortization expense by $217,250 for the 2010 test year. We also reduce jurisdictional working capital by $2,948,000 for the 2010 test year.

Energy Conservation Cost Recovery Clause

FPL witness Ousdahl testified that:

> This company adjustment applies payroll loadings consistent with the payroll dollars recovered through the energy conservation cost recovery (ECCR) clause. Currently, FPL makes an adjustment to the ECCR clause to reduce total payroll

[70] Order No. 14030, issued January 25, 1985, in Docket No. 840086-EI, In Re: Application of Gulf Power Company for authority to increase its rates and charges; Order No. 16313, issued July 8, 1986, in Docket No. 850811-GU, In Re: Petition of Peoples Gas System, Inc. for authority to increase its rates and charges in Hillsborough County; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In Re: Application of Gulf Power Company for a rate increase.

[71] See Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

> loadings related to compensation associated with conservation employees by the amount of loadings for FICA and unemployment taxes. This adjustment has been required due to a finding in Docket No. 850002-PU that these items were already included in base rates at that time. FPL is proposing to remove $1.6 million for 2010 and $1.5 million for 2011 for the FICA and unemployment taxes remaining in base rates, in order to facilitate recovery of fully loaded ECCR payroll costs through the ECCR clause beginning in 2010. The amount of these loadings varies directly with payroll costs charged to the ECCR clause, so it is appropriate that they be recovered via that mechanism.

The Company's adjustment would shift more cost to the recovery clauses. As the Company noted, we required that the loadings on payroll recovered through the ECCR remain in base rates in Docket No. 850002-PU. The Company has presented no compelling reason to shift these costs from base rates to the ECCR clause.

Accordingly, the Company's proposed adjustment to remove FICA and unemployment taxes, associated with payroll through the ECCR, from base rates and to recover those cost through the ECCR clause is denied. Based on the foregoing, O&M expenses are increased by $1,582,000.

FPL proposed that payroll loadings on incremental security costs, currently included in base rates be recovered through the Capacity Cost Recovery Clause. Several intervening parties opposed this change and we were asked to determine if those payroll loadings should be moved from rate base to the Capacity Cost Recovery Clause.

FPL witness Ousdahl testified that:

> This company adjustment applies payroll loadings consistent with the payroll dollars recovered through the capacity clause. Currently, FPL has not been including payroll taxes related to compensation associated with incremental security through the capacity clause. FPL proposes to remove $430 thousand from base rates in the 2010 Test Year and $506 thousand from the 2011 Subsequent Year for payroll taxes related to compensation associated with incremental security, in order to facilitate recovery of fully loaded incremental security payroll costs through the capacity clause beginning in 2010. These loadings are incremental and vary directly with incremental security payroll costs charged to the capacity clause.

We find that the Company's adjustment would shift more cost to the recovery clauses and that the Company presented no compelling reason to do so. Based on the foregoing, the Company's proposed adjustment to remove FICA and unemployment taxes, associated with payroll recovered through the capacity clause, from base rates and to recover those cost through the capacity clause is denied. O&M expenses are increased by $427,000 for the 2010 test year.

ATTACHMENT B

Incremental Hedging Costs Recovered through the Fuel Cost Recovery Clause

FPL proposed to move incremental hedging costs to rate base. "Incremental" hedging costs are administrative costs such as labor cost, as opposed to "actual" hedging costs which are the prudently-incurred gains and losses from fuel price hedging activities. Actual hedging costs are charged to the fuel cost recovery clause pursuant to Order No. PSC-02-1484-FOF-EI.[72] In addition, actual hedging costs are much larger than incremental hedging costs.

Witness Ousdahl testified that:

> Incremental hedging costs of $715,000 for 2010 primarily consisted of the labor costs associated with the trading, back office, and middle office staff employed in support of the Company's Commission-sanctioned fuel hedging program. In accordance with Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, incremental costs associated with the Company's hedging program were recoverable as a part of the fuel clause until the earlier of 2006 or the establishment of new base rates in the Company's next base rate case. FPL's clause recovery of its incremental hedging costs was extended in Docket No. 050001-EI, Order No. PSC-05-1252-FOF-EI, issued on December 23, 2005, through at least December 31, 2009 and thereafter until FPL's next base rate proceeding. At this time, it is appropriate to include these costs in the current base rate revenue requirements calculations.

Consistent with our prior orders, we move incremental hedging costs into base rates. The incremental hedging costs are administrative costs and properly belong in base rates, not in fuel factors.

Exhibit 180, MFR Schedule C, showed adjustments to increase jurisdictional expenses by $702,000 for the 2010 test year. FPL made several corrections to its original filing, including corrections to its inclusion of incremental hedging costs in rate base. FPL witness Ousdahl sponsored Exhibit 358 which summarized the adjustments to rate base, net operating income, and capital structure that FPL proposed we make to its original filing. Item 20 of Exhibit 358 showed FPL's proposed adjustment due to an over-statement of O&M cost associated with hedging cost. In its original filing the Company overstated the increase in O&M cost by $52,000. Based on the foregoing, the Company's proposal to move $650,000 ($702,000 - $52,000) of incremental hedging costs into rate base for the 2010 test year is approved.

O&M Expenses

We were asked to determine if FPL's proposed O&M expenses were appropriate, with the adjustments made by FPL. This is a fallout issue and its determination is based on our decisions above. However, FPL proposed one additional adjustment to its filings for O&M expenses. FPL witness Ousdahl sponsored Exhibit 358, which summarized the adjustments to

[72] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re:Review of investor-owned electric utilities' risk management policies and procedures.

rate base, net operating income, and capital structure that FPL proposed to its original filing. Item 2 of Exhibit 358 showed FPL's proposed adjustment due to the possibility that poor investment performance in 2008 might affect Nuclear Electric Insurance Limited's (NEIL) ability to make future distributions. FPL witness Ousdahl testified that "In early 2009, when the 2008 performance became known, the Company should have revised its forecast to reflect the expectation of no distributions in 2010 and 2011 prior to filing its MFRs. This adjustment corrects that oversight."

Unlike most of the adjustments to the Company's filing shown in Exhibit 358, Item 2 is not a correction of an error but an update to one item of expense in the Company's entire forecast. This adjustment is based on a possible elimination of distributions based on information that became known to the Company in early 2009 after it had filed its case. First, we do not believe it is appropriate to update one item of expense in the Company's entire forecast without updating all items of revenue and expense. Second, the Company has not had any communication with NEIL wherein it was communicated that there would definitely be no distributions in 2010 and future years. NEIL has made distribution for many years without interruption. Accordingly, we deny FPL's proposed adjustment shown on Item 2 of Exhibit 358. Based on the foregoing, the appropriate level of O&M - Other expense is $1,475, 020,037 for the 2010 projected test year, and is shown on Schedule 3 of this Order.

Customer Information System

FPL acknowledged that it should not be permitted to collect depreciation expense for its new Customer Information System before its implementation date. FPL contended that its proposed depreciation expense was overstated by $0.4 million in 2010. In rebuttal testimony, FPL witness Ousdahl stated that there was a problem with FPL's projection of plant in service and depreciation expense for the Customer Service Information (CIS III) replacement project. The error was not detected until the Company responded to SFHHA's Tenth Set of Interrogatories, question number 288. Witness Ousdahl further stated that rate base was understated by $2.0 million due to the accumulated depreciation in 2010. Witness Ousdahl testified that the applicable adjustments and the revenue requirement impacts were shown in her Exhibit 358 Items 11 and 12.

We reviewed the adjustments made by FPL in Items 11 and 12 of Exhibit 358 and concur. The adjustments corrected the depreciation expense error for the CIS III replacement project. Item 11 of Exhibit 358, reduced the 2010 expenses by $435,000. Item 12 of Exhibit 358, adjusted the impact of the CIS III error correction for accumulated depreciation and was discussed above. Accordingly, we reduce the 2010 depreciation expense by $435,000.

Capital Expenditure Reductions

We reviewed the proposed depreciation expense adjustments for 2010 as reflected in FPL's exhibits. The capital expenditure reductions that corresponded to Exhibit 358 were the DOE Settlement, the customer information system, the transmission services, and error corrections to Account 354. The depreciation expense reductions for 2010, as reflected in FPL's exhibits, totaled $14,936,000. As we discussed above regarding levels of plant in service, capital expenditure reductions were provided for aviation costs and deferred or delayed projects with the corresponding depreciation expense for 2010 in the amount of $2,303,009. When discussing levels of plant in service, we also reviewed SFHHA's proposal of an annualized adjustment for 2010 plant in service in the amount of $784,000,000 and declined to make that adjustment. Based on the foregoing, the total capital expenditure reductions for 2010 is $17,239,009. These reductions for depreciation expense are included with all other depreciation reductions in Table 24 on the following page.

Depreciation expense adjustment

We were asked to determine what adjustments, if any, should be made to depreciation expense. Our decision on what adjustments is a culmination of our other decisions in this docket. As shown in the table below, we identified all of the adjustments to depreciation expense that we have made. Each adjustment for depreciation expense corresponds to adjustments we made for: jurisdictional separation; depreciation study, capital recovery schedules and reserve surplus; fossil dismantlement study; plant in service; aviation costs; customer information system-CIS3; and correction of errors by the Company. In addition, based on the results of the depreciation study, we developed the composite depreciation rates that were used for the 2010 test year depreciation expense calculation.

TABLE 24

2010 Adjustments to Depreciation Expense			
Description	FPL	OPC	Commission
Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services			
Issue 108: EXH 358-Item 4-DOE Settlement	($747,000)	0	($747,000)
Issue 129: EXH 358-Item 12 CIS III	($435,000)	0	($435,000)
EXH 358 Issue 16 Account 354 correction	($3,419,000)		($3,419,000)
Issue 15: EXH 358-Item 21-Transmission Services–jurisdictional factor	($10,335,000)	0	($10,335,000)
Issue 50: EXH 418-Deferred Projects	0	0	($211,000)
Issue 94: Aviation Costs	($2,092,009)	0	($2,092,009)
Issue 19C and 19D: Depreciation Study	0		($82,735,000)
Issue19E and 19F: Allocation of Reserve Surplus			($223,695,000)
Issue 121: Fossil Dismantlement Study			$2,640,568
Total Reductions	($17,028,009)	($560,659,000)	($321,028,441)

Accordingly, based on the adjustments reflected in the table above, the appropriate adjustment to depreciation expense for 2010 shall be a reduction of $321,028,441. The effect of the adjustments for the 2010 test year is a depreciation expense of $753,236,559.

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Taxes other than income taxes

FPL witness Ousdahl sponsored Exhibit 358 in her rebuttal testimony, which summarized the additional adjustments to rate base, net operating income, and capital structure that FPL proposed to its original filing. Item 9 of Exhibit 358, showed FPL's proposed adjustment to reflect an increase in state unemployment tax rates that were inadvertently excluded from the Company's MFRs. This adjustment increased jurisdictional taxes other than income taxes by $972,000 for 2010. FPL's corrections to its original filing presented in Exhibit 358 were not challenged and appear to be reasonable. Accordingly, we accept FPL's adjustment of $972,000. Based on the other adjustments made in this Order, in addition to this adjustment, we find that taxes other than income taxes are $344,962,130.

The American Recovery and Reinvestment Act (Stimulus Bill)

We reviewed whether an adjustment should be made to reflect any test year revenue requirement impacts of the Stimulus Bill signed into law by the President on February 17, 2009. On August 6, 2009, FPL submitted a grant application to the United States Department of Energy for the Smart Grid Investment Grant. The maximum award for the grant was $200 million. As of the end of this proceeding, FPL had not received a response on its DOE Smart Grid Investment Grant application.

FPL witness Santos testified that the grant would be used for incremental projects. Witness Santos testified that the DOE was looking for new projects that would stimulate the economy. Witness Santos testified that FPL would likely begin to receive the grant money during the 2010-2011 timeframe. FPL asserted it would use the grant money on projects it had not planned on doing in the areas of transmission, distribution, and home area networks. The grant would also allow FPL to install smart meters in the industrial class, which was not something that was a part of FPL's original rate forecast. Witness Santos testified that the grant money, when received, would be applied like a contribution in aid of construction. The money would reduce the future plant in service balance.

SFHHA stated that the receipt of the grant for Smart Grid would allow FPL to realize extra savings, and therefore we should reduce rate base by $20 million. SFHHA also argued that the stimulus act has allowed FPL to accumulate an additional $884 million dollars in tax benefits.

SFHHA witness Kollen testified that revenue requirement should be reduced by at least $20 million. The witness further testified that the grants and other savings associated with the receipt of the grant should be used to reduce revenue requirement. Witness Kollen testified that the Company should defer the amount of the grant and the associated depreciation and use the grant money, when received, to reduce the account by the amount of the grant.

We find that the Smart Grid Investment Grant will allow FPL to accelerate investment in smart grid technology. The investment is in incremental projects and not projects that are being recovered through rate base. Since FPL proposes to use the grant like a CIAC contribution, it will not receive any return now, or in the future, on any money received from the grant.

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Customers will receive the benefits of having smart meters and a smarter infrastructure, affording them more information on their usage. As we discussed above, implementation of smart grid technology will have significant cost savings to FPL customers. In recognition of the cost savings that will be realized by FPL, we direct FPL to bring us a program to help customers use AMI to reduce energy consumption. Accordingly, we make no adjustments to the 2010 test year for this issue. We note that we addressed the affects of any accumulated tax benefit and any adjustment for bonus depreciation previously in this order.

Income Tax Expense

FPL originally proposed an income tax expense of $243,338,000 for the 2010 projected test year. However, due to a number of subsequent adjustments, FPL proposed an updated 2010 jurisdictional projected income tax expense of $248,680,000. FPL asserted that after accounting for the adjustments in Exhibits 358, 481, 511, and 514, the projected income tax expense for 2010 is appropriate. Each of the intervening parties suggested adjustments based on their recommendations in other issues.

The income tax expense is a result of other adjustments we made in this Order. Reductions to expenses we made increase the income tax expense based on the statutory income tax rate of 38.575 percent. Based on our decisions above, the requested total income tax expense of $243,338,000 shall be increased by $223,207,072 resulting in an adjusted total income tax expense of $466,545,072, and is shown on Schedule 3 attached to this Order.

Projected Net Operating Income

A determination of the appropriate net operating income for the projected test year is a culmination of our other decisions in this Order. Based on our decisions in this Order, the appropriate net operating income is $1,070,179,348 for the 2010 projected test year, and is shown on Schedule 3 to this Order.

REVENUE REQUIREMENTS

Revenue expansion factors

FPL stated that the appropriate projected 2010 revenue expansion factor was 1.63411 (1.63342 per original filing). According to FPL, the elements and rates were shown on MFR C-44, and then adjusted by Exhibit 358. OPC proposed that the appropriate net operating income multiplier for the 2010 test year was 1.630911.

We agree with FPL's bad debt rate adjustments in Exhibit 358. These adjustments increase the bad debt rate from 0.260 percent to 0.302 percent for 2010. We find that the Company's calculations are correct and that the appropriate revenue expansion factors and the appropriate net operating income multipliers are 61.195 percent and 1.63411, respectively, for the 2010 projected test year. The appropriate elements and rates are shown on Schedules 4 attached to this Order.

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Annual operating revenue increase

Our decision on the annual operating revenue increase is a culmination of our decisions in this Order. Based on our decisions, the appropriate annual operating revenue increase is 75,470,948 for the 2010 projected test year and is shown in Schedule 5, attached to this Order.

COST OF SERVICE AND RATE DESIGN

Revenue Calculations

Consistent with our decision to revise FPL's forecast of billing determinants, we have recalculated the revenue at current rates for 2010.

Minimum Distribution Cost Methodology

The issue of the classification of distribution costs was raised by SFHHA witness Baron. Distribution costs are composed of both demand and customer related costs. Distribution demand related costs are allocated to classes based on the class's non-coincident peak demand (NCP) and customer related costs are allocated on the basis of number of customers. How distribution costs are classified between demand and energy can impact how costs are allocated and how much distribution cost is recovered from each class.

Witness Baron noted that FPL has followed our historical practice of classifying all costs in Account 364, Poles, Towers and Fixtures, as demand related and allocated to rate schedules on the basis of rate class NCP demand. Witness Baron argued that this proposed classification results in too little of the distribution facilities costs, such as poles and transformers, being allocated to the residential and small commercial classes and leads to commercial and industrial customers paying too much for facilities that do not benefit them.

Witness Baron proposed to classify more of the distribution costs as customer-related, by establishing a Minimum Distribution System (MDS) construct. He noted that the MDS approach is particularly justified in the current environment because of the number of vacant residential dwellings that have little or no demand and therefore are not allocated any distribution costs using a non-coincident peak demand (NCP) allocator. The primary reason for adopting the MDS classification approach is that it recognizes, to some extent, there is a minimum cost to interconnect a customer to the system and that accordingly, it is appropriate to allocate costs associated with primary and secondary lines and transformers on a customer basis as opposed to a demand basis.

FPL witness Ender stated in his rebuttal testimony that the MDS system presumes a type of electric system and a method of planning that does not reflect how FPL designs its distribution system. He asserted that the zero or minimum load requirements of customers is purely fictitious because no utility builds to serve zero load. Witness Ender argued that the MDS approach shifts all benefits obtained from economies of scale to large customers, even though there are similar economies of scale in serving residential load. For example, he explained, the diversity of load inherent in residential use allows the addition of new customers without the need for new poles

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or transformers. No such diversity is applicable to commercial customers who require a single pole and transformer. Witness Ender also contended that the MDS methodology double counts the kW load for smaller customers because residential and small commercial load would first be assigned the assumed minimum distribution costs, and would then be assigned additional costs based on their non-coincident Peak (NCP) demand, with no adjustment for the costs already assigned under the MDS. FPL also argued in its Brief that use of the MDS methodology would drastically increase the amount of distribution plant costs allocated to residential and very small commercial customers.

We have consistently rejected the MDS methodology on numerous occasions in the past. The most recent discussion on MDS took place in the 2001 Gulf Power Company rate proceeding. In that docket, we found that:

> [Gulf Witness] Mr. O'Sheasy describes MDS as identifying the costs of the facilities needed to simply hook-up a customer to the power system. Yet, distribution lines must be connected to subtransmission and transmission lines and ultimately to the busbar at the power plant in order to be able to deliver a single kWh. To artificially separate distribution accounts on the basis that these facilities are necessary to make service available ignores the way the electric system works. MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines. As cited in the order in Gulf's last rate case:
>
> > There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, and customers served at higher voltages would not pay for any of this network path.
> >
> > We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.
> >
> > In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer related.[73]

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[73] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for Rate Increase by Gulf Power Company, p. 64

In FPL's 1981 rate case we found:

> The Company and the Commission Staff have proposed the use of a theoretical minimum distribution system as part of the customer charge. We believe the appropriate customer charge should be based only upon the cost of the meter, service drop, meter reading and basic customer service costs.[74]

We affirmed that position in FPL's 1982 rate case and again in Tampa Electric's 1982 rate case. The FPL order states:

> FIPUG contended that the concept of the minimum distribution system should be recognized in a cost of service study. However, in recent rate cases, we have not approved use of the minimum distribution system in classifying costs and no evidence was presented in this case to persuade us to depart from this policy.[75]

The 1982 Tampa Electric Company order states:

> In designing rates we have selected the Staff Requested Cost of Service Study (Exhibit 22-D) using the 12 CP and weighted one thirteenth average demand allocation methodology. The major philosophical differences between the Staff Requested Study and the Company's 12 CP and average cost of service study are that the Staff Requested study does not recognize the concept of the minimum distribution system, allocates the uncollectible expense to all customer classes on the basis of revenues and classifies conservation costs as energy rather than customer related. The Staff's treatment of all three of these items is correct.[76]

We again addressed the MDS methodology in Florida Power Corporation's (PEF) 1982 rate case:

> FIPUG contended that the Commission should select a cost of service study for use in designing rates that recognized the concept of the minimum distribution system. In the last four electric utility rate cases, we have determined that only the meter and service drop portion of the distribution system are properly classified as customer related. The evidence presented by FIPUG has not persuaded us to change our minds. For this reason, we selected a Staff Requested cost of service study which does not recognize the minimum distribution system concept for use in this proceeding.[77]

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[74] Order No. 10306, issued September 23, 1981, in Docket No. 810002-EU, <u>In re: Petition of Florida Power & Light Company for authority to increase its rates and Charges, p. 43.</u>

[75] Order No. 11437, issued December 22, 1982, in Docket No. 820097-EU, <u>In re: Petition of Florida Power and Light Company to increase its rates and charges, p. 43.</u>

[76] Order No. 11307, issued November 10, 1982, in Docket No. 820007, <u>In re: Petition of Tampa Electric Company for an increase in rates and charges,</u> p. 36.

[77] Order No. 11628, issued February 17, 1983, in Docket No. 820100-EU, <u>In re: Petition of Florida Power Corporation to increase its rates and charges,</u> p.35-6.

In Tampa Electric Company's 1980 rate case, we noted that our staff and the company had proposed a theoretical minimum distribution cost as part of the customer cost. We found:

> While we agree that sound regulatory practice should provide for a customer charge to defray otherwise fixed costs, as proposed by the Company and the staff, we do not agree that a theoretical cost of a minimum distribution system is appropriate. . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. Reliance on such a mechanism is speculative at best. Instead, we believe the appropriate customer charge should be based upon the cost of the meter, service drop, meter reading and basic customer services costs (not including uncollectibles).[78]

In a Florida Power Corporation (now PEF) case in 1980, we stated:

> The company has proposed increases in the level of the customer charges in all rate classifications. As in previous cases (Orders 9599 and 9628), we feel that the distribution costs which should be included in the customer charges consist of those related to distribution from the pole to the customer's structure.[79]

SFHHA also pointed out that the MDS methodology requires that assumptions be made, for each FERC account, on the minimum size of a particular component that would be required to serve customers without respect to the ultimate level of demand. Witness Baron provided no objective criteria for determining which costs should be classified as customer related as opposed to demand related. In Order No. PSC-02-0787-FOF-EI we stated:

> We find that the simpler, more straightforward approach of allocating only service drops and meters on a customer basis adequately captures the distribution investment that is solely required to extend service to a new customer. This methodology is clear, generally accepted, and requires no series of hypothetical cost and system design calculations that do not reflect how the actual system is designed. . . .
>
> For the reasons provided above, we find that the treatment of distribution costs shall remain consistent with our past decisions, and accordingly, only Accounts 369 and 370 shall be classified as customer related.[80]

While we have approved an MDS approach for a Rural Electric Cooperative, that order contains specific conditions inherent in the Cooperative's customer base that makes the use of

[78] Order No. 9599, issued October 17, 1980, in Docket No. 800011-EU, <u>In re: Petition of Tampa Electric Company for an increase in its rates and charges</u>, p. 18
[79] Order No. 9864, issued March 11, 1981, in Docket No. 800119-EU, <u>In re: Petition of Florida Power Corporation for authority to increase its rates and charges</u>, p. 31.
[80] Order No. PSC-02-0787-FOF-EI, p. 66

MDS appropriate for that utility.[81] Witness Baron was unable to state conclusively that the conditions precedent to our decision in Docket No. 020357-EC were present in the FPL rate case. Therefore, it is not appropriate to rely upon that order to justify using the MDS methodology for FPL. Witness Baron also relied on five orders from other states to support the use of the MDS. While he maintained that he had personal knowledge of the use of MDS by these five utilities, nothing in the orders provided described the use of MDS or why the respective utility Commissions believed the MDS approach was appropriate. We will not rely on such unverified representations and incomplete information about conditions found in utilities in other states to make a decision for a Florida utility.

We have a long history of limiting the costs that are allocated on a customer basis and recovered through the customer charge. As pointed out by FPL witness Ender, FPL plans and constructs its distribution system based on expected load, not customers served. The number and size of poles and transformers is driven by the size of the load to be served, whether for commercial or residential customers. In addition, the MDS requires value judgments to be made on an account by account basis for several FERC accounts in order to arrive at the distribution costs to be assigned on a customer basis. This introduces an unnecessary element of discretion and judgment into the cost allocation process. Witness Baron has not presented any convincing evidence on either the calculation of MDS costs, or the appropriateness of using the MDS approach, that justifies this change to our longstanding policy.

We do not adopt the proposed minimum distribution system to classify Account 364 costs on a customer basis. Distribution costs shall continue to be allocated to rate classes using the methodology proposed by FPL.

Cost of Service Methodology

The purpose of a cost of service study is to form a cost basis for establishing revenue requirements for each rate class. The cost of service is a matter of judgment, and there is no one correct cost allocation methodology. While the 12 CP and 1/13 methodology has been the dominant methodology in the past, we have also approved different methodologies. Most recently, in the Tampa Electric Company rate case, we approved the 12 CP and 25 percent energy methodology.[82] That method increased the proportion of production demand costs that are allocated on energy from eight percent to 25 percent. Other than the treatment of St. Lucie Unit 2, FPL has not proposed to change its cost of service methodology. FPL witness Ender testified that FPL made a judgment call and believed that the right methodology for this case is the 12 CP and 1/13 methodology because it is consistent with the manner in which FPL plans its generation system. The 12 CP and 1/13 method recognizes that both energy and peak demand influence the type of generation unit that is added. The method also recognizes that FPL must meet the peak demands for every month.

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[81] Order No. PSC-02-1169-TRF-EC, issued August 9, 2002, in Docket No. 020357-EC, In re: Petition for Modifications of Electric Rate Schedules by Choctawhatchee Electric Cooperative.

[82] Order No. PCS-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

SFHHA Witness Baron testified that a more reasonable cost of service study for FPL is a method based on a summer CP methodology. Under the summer CP methodology, cost of production plant would be allocated among FPL's rate classes according to their contribution to the summer coincident peak. The summer CP methodology is only taking one hour in the summer as the basis for allocating costs. In cross-examination of witness Ender, SFHHA established that the coincident peaks in the months of June, July, August, and September were higher than the coincident peaks in any other months in 2005, 2006, 2007, and 2008. Witness Ender also agreed that the forecasted summer coincident peaks on FPL's system for 2009, 2010, and 2011 will be higher than the coincident peaks in any other months of the year. Witness Ender added, however, that the summer coincident peaks are higher, but only slightly so in some cases.

FIPUG Witness Pollock testified that while FPL is a summer peaking utility and experiences its tightest margins during the summer months, we have adopted the 12 CP and 1/13 in past cases, and it should not be replaced with another method that places greater emphasis on energy usage. Witness Pollock stated that should the Commission decide to replace the 12 CP and 1/13 method, it should adopt the Average and Excess (A&E) method because it recognizes the dual functionality of generating plants. Some plant is required for year-round operation, i.e., average demand, and the remaining plant is required for cycling, i.e., excess demand. Under the A&E method 59 percent of production and transmission plant would be allocated on average demand. The remaining costs, or the excess demand component, would be allocated to rate classes based on the difference between the class maximum demand and their average demand. Witness Ender rejected the A&E method, stating that class maximum demand is rarely coincident with the peak demand on the system, and the use of this non-coincident demand to allocate production and transmission plant is inconsistent with FPL's generation plan.

In his rebuttal testimony, witness Ender testified that the 12 CP and 1/3 methodology accurately reflects FPL's generation plan because it (1) it recognizes that the type of generation unit is influenced by both energy and peak demand; (2) it reflects the influence of the summer reserve margin; and (3) it recognizes that capacity must be available throughout the year to meet FPL's winter reserve margin and the annual loss-of-load probability criteria.

Witness Ender also testified that while the summer reserve margin criterion of 20 percent currently drives FPL's need for new resources, we should not accept SFHHA's proposed use of the summer CP methodology for the following reasons: (1) the summer CP method is inconsistent with FPL's generation planning process; (2) the summer CP allocation does not send a better price signal than the 12 CP and 1/13 methodology; and (3) the summer CP method would allocate no production costs to two rate classes even though all rate classes receive the benefit of FPL's generation capacity. The two classes that would not be allocated any productions costs are the OL-1 (outdoor lighting) and SL-1 (street lighting) rate classes. That is because generally in the summer the peak occurs during the daylight hours and the lights are not on, and therefore those classes make no contribution to production costs. If no costs are allocated to the OL-1 and SL-1 rate classes, those costs would be allocated to the other classes. Witness Ender added that the reason the 12 CP and 1/13 method was approved was because it provided some cost responsibility to all rate classes.

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Witness Ender explained that SFHHA's proposed use of the summer CP allocation method would shift costs away from the medium and large commercial rate classes, onto residential and small commercial classes. Witness Ender explained that the use of the summer CP method does not recognize the energy component of the energy usage, and as a result, it would shift costs over to the higher demand customers like residential and general service, which are small commercial customers. Witness Ender also stated that witness Baron represents customers that are in rate classes that would receive a fairly significant reduction in cost allocations as a result of witness Baron's proposed methodology.

We find that the appropriate cost of service methodology for production and transmission plant, including St. Lucie Unit 2, is the 12 CP and 1/13 methodology. Both witness Baron and witness Ender made persuasive arguments regarding the appropriate cost of service methodology. However, based on the review of the evidence, we are of the opinion that the record more strongly supports FPL's continued use of the 12 CP and 1/13 methodology, as it more appropriately reflects FPL's generation plan, and recognizes both demand and energy in allocation costs to all rate classes.

Revenue Requirement Allocations

This section addresses the allocation of any revenue increase to the various rate classes. Rate classes are groups of individual rate schedules with similar billing attributes and rate design relationships, so they are treated for rate design purposes on a combined basis.[83] FPL, FIPUG, and SFHHA disagreed on whether any increase to a particular rate class should be limited to no more than 1.5 times, or 150 percent, the system average. When a rate increase limit is imposed on a rate class, the remaining classes will have to absorb that difference. Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase.

FPL set the target revenues by rate class in order to obtain parity among the classes to the greatest extent possible without limiting any rate classes' increase to 1.5 times the system average. A rate class is at parity if it is earning the same as the system retail rate of return. FPL witness Ender testified that FPL's current rates were set over 20 years ago in FPL's last fully litigated rate case, Docket No. 830465-EI, and since that time customer rates have been adjusted several times without regard to parity levels. FPL witness Deaton stated that FPL's proposal provides an opportunity to address inequities between the rate classes at a time when overall bills are projected to decrease for most customers in 2010, with moderate increases in 2011. Bills on average will decrease in 2010 as a result of a reduction in fuel costs and increased efficiencies in FPL's system. Witness Deaton further testified that taking a more gradual approach and not moving to parity to the fullest extent practicable now would result in the continued subsidization of certain rate classes by others. Witness Deaton stated that for a number of years, medium and large commercial and industrial customers have benefited from a subsidy by residential and small commercial customers. Larger commercial/industrial rate classes are below parity and need to be brought up to parity in order to carry their fair share of the cost. Finally, Witness Deaton testified that the larger commercial/industrial customers are heavier energy users. They

[83] For example, time-of-use rate schedules are combined with their non-time-of-use counterparts.

will see larger benefits in the fuel savings, and should therefore pay their fair share of the production costs that produce those benefits.

To support its position, FPL relied on two previous decisions in which we did not limit the increase to 1.5 times the system average. First, FPL stated that in the 1982 Gulf Power Company (Gulf) rate case, we departed from the policy to limit the increase to any one class to no more than 1.5 times the system average.[84] In the Gulf order we stated; "were we to apply that policy in this case, some classes whose present rates of return are above parity, would receive an increase. Thus, the greater equity lies in allocating the increase to those classes with substantially lower rates of return." In 1982, Gulf had six rate classes, and the Residential (RS) and Outdoor Service (OS) rate classes were below parity, while the four commercial rate classes were well above parity. The Commission divided the revenue increase between the RS and OS rate class.

The second order FPL relied on involved a recent Peoples Gas System (PGS) rate case.[85] In that decision, we allowed increases to rate classes greater than 150 percent of the system average. We are of the opinion that the PGS case presented unique circumstances, and different considerations go into setting gas rates. In our view, the PGS case does not provide a reasonable basis to support FPL's position.

Witness Deaton also referenced the 1981 FPL rate case order in her rebuttal testimony. In that order we ruled that no customer class shall receive a revenue increase greater than 1.5 times system average increase.[86] Witness Deaton argued, however, that in that order we indicated that this guideline was designed to mitigate the impact on customers' bills, and not out of some general principle of slowly moving towards parity and allowing cross-subsidization to continue.

FIPUG witness Pollock testified that the Commission should continue to apply the principle of gradualism to any base revenue increase that may be approved in this case, notwithstanding any predictions about subsequent changes in cost recovery clauses. Witness Pollock further added that the cost recovery clauses are separate ratemaking mechanisms and can have positive or negative impacts on customers depending on the circumstances, and any projected short-term changes should not be considered in setting base rates.

We agree with Witness Pollock that cost recovery clauses can have a positive or negative impact on bills, and FPL's projection of a decrease in fuel prices for 2010 is not a valid reason to not apply the concept of gradualism. Upon cross examination, Witness Deaton agreed that fuel is volatile. Furthermore, FPL does not know what fuel prices will be in 2011. Witness Deaton testified that FPL does not know, for example, if there might not be some fuel disruption, and a consequent spike in fuel prices that could amount to an increase in the total bill. Conversely,

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[84] Order No. 10557, issued February 1, 1982, in Docket No. 810136-EU, In re: Petition for Gulf Power Company for an increase in its rates and charges.
[85] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.
[86] Order No. 10306, issued September 23, 1981, in Docket No. 810002-EU, In re: Petition of Florida Power & Light Company for authority to increase its rates and charges.

FPL does not know if there will be further fuel reductions. Furthermore, approximately 70 to 80 percent of FPL's fuel costs reflect natural gas prices, and natural gas prices are volatile. While Witness Deaton testified that fuel prices will not go up as much as they would have, absent efficiency savings that FPL is making on its system, Witness Deaton also stated fuel prices vary from period to period.

SFHHA Witness Baron testified FPL has not implemented any material measure of gradualism or mitigation in assigning increases to the rate schedule. Witness Baron stated that under FPL's proposed increases, some commercial rate schedules will receive increases of 50 percent to 60 percent. Witness Baron rejected FPL's position that prior rate case settlements and other factors have limited our full consideration of cost of service and rate parity. Witness Baron testified that each case rests on its own merits, and FPL agreed to past rates that were a result of a settlement. Witness Baron stated that FPL's position seems to be that the prior settlements produced unjust rates and therefore in this case it is necessary to fix the problem and address those past mistakes.

From our review of our prior decisions, it is clear that we have discretion in whether to apply the 1.5 limit in this case. While it is true that we did not apply this limit in the 1982 Gulf rate case, in more recent electric rate cases we have decided that no class should receive an increase greater than 1.5 times the system average.[87] FPL, FIPUG, and SFHHA raised valid arguments in support of their positions. We are persuaded by FIPUG's and SFHHA's testimony that fuel costs are volatile and could increase in the future, thus raising overall bills again. The timing of FPL's rate case filing could have also happened during a period of increasing fuel costs.

Consistent with our decisions in more recent electric rate cases, we find that in this case no class shall receive an increase greater than 1.5 times the system average percentage increase in total, i.e., with adjustment clauses, and no class should receive a decrease. When calculating the percentage increase, FPL shall use the approved 2010 adjustment clause factors.

Service Charges

Initial Connect

The initial establishment of service charge is collected to cover the cost for the work required to connect a location to FPL's infrastructure. FPL's current rate for the initial connection of service is $14.88, and the proposed rate is $100.00. A cost study was completed to evaluate the cost the company incurs for this service. The cost established was $135.95. FPL Witness Santos stated that a service charge of $100 is a reasonable charge, based on the work required for the initial connect/disconnect activity. In its brief and during cross examination of FPL witness Santos, the AG, raised concerns with this higher charge for initial connect. Upon

[87] Order No. 080317-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PCS-02-0787-FO-EI, issued June 10, 2002, in Docket No. 010949, In re: Request for rate increase by Gulf Power Company.

consideration we find that it is appropriate at this time to keep the current charge of $14.88 for initial connection of service in place

Field Collection

The field collection charge is added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If the service is disconnected, or a current receipt of payment is shown at the time of the field visit, no charge would be applied. FPL's current rate for the field collection charge is $5.11 and the proposed rate is $19.00. Upon consideration we find that it is appropriate at this time to keep the current charge of $5.11 in place.

Reconnect for Non-Payment

The reconnection charge covers FPL's cost of reconnection of service after disconnection for nonpayment or violation of a rule or regulation. FPL's current rate for the reconnect for non-payment service charge is $17.66, and the proposed rate is $48.00. The proposed rate was set at cost of service. We find, however, upon consideration, that it is appropriate at this time to keep the current charge of $17.66 in place.

Connection of an Existing Account

The connection of an existing account charge is collected to cover the costs the company incurs to establish a new account at a location already established on FPL's infrastructure. This cost also includes the customer's subsequent disconnect of service. FPL's current rate for Non-payment Reconnect is $14.88 and the proposed rate is $21.00. The proposed rate was set at cost of service. We find, however, upon consideration, that it is appropriate to keep the current charge of $14.88 in place at this time.

Returned Payment

A returned payment charge is collected when a check or draft is not honored by the bank on which it was drawn. Currently FPL charges $23.24 or 5% of the amount of payment, whichever is greater. FPL's proposed charge would comply with Florida Statute 68.065, which specifies a tiered fee structure based on the returned payment amount:

$25 if payment amount is less than or equal to $50;

$30 if payment amount exceeds $50 but is less than or equal to $300;

$40 if payment amount exceeds $300 or 5% of the amount, whichever is greater

FPL stated that it had a 20 percent increase in returned payments from 2007 to 2008. FPL incurs additional costs when a check is returned. Customers who cause the utility to incur additional costs should be responsible for paying those costs. With these new rates, FPL hoped to create a stronger deterrent and help minimize the number of returned items received. We find, however, upon consideration, that it is appropriate to keep the current charge of $23.24 or 5% of the amount of payment, whichever is greater, in effect at this time.

In consideration of current difficult economic conditions, we find it appropriate to leave FPL's service charges unchanged.

Late Payment Charge

FPL asked to establish a minimum late payment charge that it argued would provide the appropriate incentive for customers to improve payment behavior. FPL currently charges 1.5 percent for late payments, but proposed the greater of 1.5 percent or $10. FPL stated that it had seen a steady increase in the number of customers making late payments, which it believed was driven largely by the deteriorating economy. The percent of customers with late payments increased from 21% in 2006 to 24% in 2008. This amounts to an increase of 150,000 customers on average per month. FPL argued that other industries use late payment charges greater than $10 to encourage customers to pay on time. FPL stated that the other Florida utilities that currently charge a fee similar to what FPL proposed are the City of Miramar Utilities, which charges a $15 fee, and the Lee County Electric Cooperative, which charges a $10 fee for residential customers. FPL argued that $5 would not be sufficient to encourage good payment behavior. FPL did state in its brief, however, that if we did not accept its position with respect to the new fee's effect on revenues, FPL would withdraw its late payment charge proposal. Since we did not accept FPL's position with respect to the new fee's effect on revenues, FPL has in effect withdrawn its request. Accordingly, FPL's request to establish a $10.00 late payment fee shall be denied.

Termination Factors

FPL's proposed termination factors are applied to customers taking service on the PL-1 or RL-1 rate schedule who chose monthly payments rather than a lump sum payment, and who then terminate their lighting agreement prior to the expiration of their 10 or 20 year contract period. The RL-1 rate schedule is a closed schedule, and not available to new customers. As stated in the Company's tariff sheet MFR E-14, Sixth Revised Sheet No. 8.722, and Second Revised Sheet No. 8.745, in order to terminate service the customer must provide a 90-day written notification to the company of their intent to cease service. The amount a customer pays to terminate their contract is computed by applying the termination factor to the installed cost of the facilities, based on the year in which the agreement is terminated. The company proposed to remove the 10-year and 20-year payment options from the PL-1 and RL-1 tariff, which is addressed in stipulated Issue 153.

We have reviewed the FPL's calculations and we find that the proposed termination factors are appropriate and we approve them.

Present Value Revenue Requirement

The Present Value Revenue Requirement (PVRR) multiplier is designed to produce an estimate of the cumulative cost of the project over its useful life. Under FPL's PL-1 and RL-1 lighting tariffs, FPL provides FPL-owned facilities, and the customer requesting those facilities is required to pay FPL for the facilities in a lump sum payment. The amount is the Company's total work order cost for the facilities times the PVRR multiplier. FPL provided the calculations and assumptions used to determine the PVRR in response to our staff's discovery requests.

We have reviewed FPL's calculations, and we find that the calculations used to determine the PVRR are appropriate. We approve the charges FPL has proposed.

Relamping Option

FPL currently offers a relamping option for Street Lighting (SL-1) and Outdoor Lighting (OL-1) customers who own their own lights and poles. Relamping only covers changing out light bulbs that need to be replaced. It does not cover any other maintenance or repair. As of March 2009, there were 244 accounts with fixtures covered by the current relamping option. These customers would be grandfathered in under FPL's proposed change.

FPL proposed to remove the relamping option for new customers on the Street Lighting (SL-1) and Outdoor Lighting (OL-1) tariffs. FPL argued that this change would clarify maintenance responsibilities, and eliminate potential customer dissatisfaction. FPL claimed that customers choosing this option often believe that FPL is responsible for all maintenance instead of just relamping. FPL did not provide any details on the number or frequency of customer complaints. The relamping option is the only service option available to customers who own their fixtures. If the relamping option is closed to new customers, customers who own their own units will have to secure another means for relamping their units. FPL has not proposed to change the service options for customers who lease lighting fixtures from the utility.[88]

We deny FPL's proposal to close the relamping option on the Street Lighting (SL-1) and Outdoor Lighting (OL-1) tariffs for new street light installations. Eliminating the relamping option would shift this burden to customers who may not have other readily available options for relamping. If the only issue is customer confusion over the utility's responsibility, that can be remedied by providing customers with a more detailed description of FPL's maintenance responsibilities.

Transformation Rider

Pursuant to FPL's Transformation Rider, if customers install their own transformers, FPL provides a monthly credit per kilowatt (kW) of billing demand to recognize the avoided cost. FPL proposed to revise the monthly credit from $0.39 to $0.32 per kW for 2010, and to $0.33 per kW for 2011. The credit is based on distribution secondary transformer costs as calculated in the cost of service study. The underlying assumptions and supporting calculations FPL used to develop the monthly credits are appropriate.

[88] FPL Retail Tariffs, Sheet Nos. 8.715 and 8.725.

We find that the monthly kW credit to be provided customers who own their own transformers pursuant to the Transformation Rider proposed by FPL is appropriate and we approve it.

Monthly Fixed Carrying Charge Rate

FPL's tariff provides that the Company may, at its option, provide and maintain transformers and other facilities which are required by the customer beyond the point of delivery or which are needed because the customer requires unusual facilities due to the nature of the customer's equipment.

The customer may elect to make either a lump sum payment or pay a monthly maintenance charge. FPL proposed to revise the monthly charge from 28 percent to 27 percent of the agreed installed cost of the transformers and other facilities per year. This annual facility rental charge is calculated based on the following percentage charges: adjusted return on capital, distribution maintenance, general and administrative, customer account and service, depreciation, insurance, and property taxes. These percentages total the annual facility rental charge of 27 percent.

We reviewed the assumptions used to calculate the annual facility rental charge and we them appropriate. We find, therefore, that the proposed monthly fixed charge carrying rate to be applied to the installed cost of customer-requested distribution equipment for which there are no tariffed charges shall be approved.

Monthly Rental Factor

FPL proposed to change the distribution substation facilities monthly rental factor from 1.62 percent to 1.83 percent. The monthly rental factor is applied to the in-place value of customer-rented distribution substations to determine the monthly rental fee for the facilities. This monthly rental factor is calculated based on the following percentage charges: levelized annual distribution substation factor, distribution substation maintenance factor, general and administrative factor, customer account and service factor, insurance, and property taxes. Together the percentages total the annual distribution substation rental charge. The charge is then divided by twelve to get the monthly rental factor of 1.83%.

We have reviewed the assumptions used to calculate the monthly rental factor, we find that they are appropriate, and we approve them.

Termination Factors

The long-term rental agreement for distribution substation facilities provides for a 20-year initial term. If the customer elects to terminate the agreement during the initial term, the customer is responsible for a termination fee. The termination fee is calculated by applying the termination factors to the in-place value of the facilities based on the year in which the agreement is terminated. FPL proposed to revise those termination factors.

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FPL explained that the termination fee is calculated by taking the present value of what the customer would have paid on a non-levelized basis up to the point of termination and subtracting the present value of what the customer has already paid up to that date on a levelized basis. Interest is applied to this amount using the weighted average cost of capital. At twenty years, the termination factor goes to zero.

We have reviewed the methodology used to calculate the termination factors and we find that it is appropriate. Therefore, we approve the proposed factors.

High Load Factor Time of Use Rates

The High Load Factor Time of Use (HLFT) rates were approved in the 2005 Settlement Order.[89] The Stipulation approved in that case states that the HLFT rates are designed to achieve a break-even point at a 65 percent load factor.[90] FPL has proposed no changes to the rate structure for this class, other than an increase in revenue requirements. FPL has provided the calculations underlying the HLFT rate design, showing the breakeven point is now targeted at 70 percent. The method used to design the rate is consistent with general ratemaking principles. The customer charge reflects the weighted cost of meters, drops and customer service for the class. The on-peak demand charge recovers the costs of production, transmission and one-half of the distribution costs allocated to the class. The maximum demand charge recovers the remainder of the distribution costs. The off-peak energy charge reflects the energy unit cost from the cost of service study and the on-peak energy charge collects the remainder of the class revenue requirement.

In its brief, FIPUG argued that the proposed HLFT rates would make the HLFT rate more expensive than GSLDT, unless the customer can achieve load factors above 84 percent for HLFT-2, and over 100 percent for HLFT-3, which is impractical. FIPUG recommended that the HLFT rate be designed for customers with load factors above 70 percent. FIPUG witness Pollock maintains that the HLFT rates are a derivative of the GSLDT rates and that it is essential to maintain a consistent relationship between GSLDT and HLFT to prevent customer migration.

FIPUG did not cite the source of the data used to arrive at the numbers presented in its Brief that support its contention that the proposed HLFT factor would result in higher rates for customers than the corresponding GSD rate except at unrealistically high load factors. Neither did FIPUG cite to any calculations to show that the HLFT rates are not designed for customers with load factors of 70 percent or higher, as FPL witness Deaton stated. Therefore, we are unable to verify FIPUG's assertions.

MFR Schedule E-13C presents the proposed billing determinants and rates for each rate class. Using the billing determinants (kwh and kW demand), the actual load factor for all three HLFT classes is approximately 80 percent. Given that the HLFT is an optional rate, and assuming that customers make intelligent choices about which rate is most cost effective for

[89] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.
[90] Order No. PSC-05-0902-S-EI, p. 11

them, these numbers support FPL's contention that the rate is appropriately designed for customers with load factors of at least 70 percent.

Witness Pollock is correct that FPL used the demand costs allocated to the GSD, GSLD-1, GSLD-2 and GSLD-3 (collectively GSD) rate classes to derive the demand charges for the HLFT rates. This is appropriate because the capacity needed to serve the HLFT customers is identical to the capacity needed to serve the corresponding GSD classes. Unless the HLFT customer also takes service under a separate tariff, the Commercial Demand Reduction Rider (CDR), that customer is considered a firm customer, just like other GSD customers. The HLFT rates offer lower energy charges to recognize the higher load factor of customers in that class.

Witness Pollock argued that the energy and demand charges should be the unit charge from the Cost of Service Study The HLFT rates more closely mirror the rate design proposed by FIPUG in that the on-peak demand charge is higher, and the energy charges lower, than the corresponding GSD rates. As we state in our discussion of the overall methodology for designing time-of-use rates below, we find that the methodology used by FPL properly matches costs to rates, keeping in mind rate shock and the impact on both high and low load factor customers within a class.

As stated above, FPL witness Deaton stated that the HLFT rate was designed at a 70 percent load factor. This is consistent with the proposal approved in FPL's 2005 rate case. FIPUG presented no documentation or calculations demonstrating that the HLFT rate was not designed as FPL asserted it was. Further, FIPUG presented no support for the numbers shown in its Brief, where it alleged that the proposed design would result in HLFT rates higher than the GSD rates except at unrealistically high load factors. We will address FIPUG's remaining arguments on the design of time-of-use rates in general, including the appropriate method for setting energy and demand charges, in the Rates and Charges section below. Here we find that FPL's methodology used to design the HLFT rate is appropriate.

Commercial Industrial Load Control Rate

FPL's Commercial Industrial Load Control (CILC) program is a demand side management program. Unlike similar programs for PEF and TECO, the revenue requirement used to set the CILC base rates is reduced to recognize the costs avoided by the ability to interrupt CILC load.[91] There is no separate credit. In response to the Public Utility Regulatory Policies Act of 1978 (PURPA), we opened a generic docket on the feasibility of implementing load management techniques by electric utilities. In that docket, we cited the PURPA definition of load management as "any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, or other types of interruptible service, energy storage devices and load limiting devices."[92] In that order, we stated that a load management technique shall be cost-effective if the long run cost

[91] Interruptible rates for Progress Energy Florida (Docket No. 090079-EI) and Tampa Electric Company (Docket No. 080317-EI) have a base rate set on fully allocated cost, with a separate credit applied to load subject to interruption.
[92] Order No. 8951-A, issued September 7, 1979, in Docket No. 790594-EI, In re: General Investigation of the feasibility of implementing load management techniques by the electric companies, p. 1

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savings to the utility of such reductions are likely to exceed the long run costs to the utility associated with the implementation such techniques.[93]

Commission Order No. 18259 approving the initial trial CILC program approved credits on each monthly bill to reflect a reduction in the utility's coincident peak demand sufficient to avoid construction of a new generating unit.[94] That order goes on to explain that the credit would be based on the cost of the utility's next avoided generation unit.[95]

FPL modified the per-KW credit approach used in the original CILC pilot when it requested approval of a permanent CILC program. The rate was restructured from a flat dollar credit per KW to a design that set charges to reflect the different types of costs incurred to provide service. The base demand charge was divided into three components: maximum demand charge; firm on-peak demand charge; and load control on-peak charge (transmission). The permanent tariff using this rate structure was approved by Order No. 22747.[96] Certain non-rate provisions of the proposed permanent CILC rate schedule were protested and then resolved by Order No. 23709 in that docket.

Maximum demand charge The maximum demand charge consists of distribution costs. Consistent with the method used to design other demand rates, the distribution costs are allocated to the class based on non-coincident KW demand because the distribution system must support the customer's maximum demand whenever it occurs.

On-peak demand charge Consistent with all other rate classes, the on-peak demand charge is derived by dividing the demand costs allocated to the class by the firm coincident on-peak demand. Any individual CILC customer may choose to operate on peak, and FPL must provide capacity to meet that demand. Therefore, it is appropriate for customers using firm capacity on-peak to pay a proportionate share of those demand costs. The on-peak charge consists of costs associated with production and transmission costs, and is assessed only to KW demand which occurs during the on-peak period. This charge can be avoided by operating off-peak.

Load control on-peak charge. The load control on-peak demand charge recovers the allocated cost of transmission divided by the KW load subject to load control. Order 18259 noted that transmission costs are not likely to be reduced by scattered CILC load reductions. As a result, CILC customers pay a transmission charge on the total demand subject to load control.[97] Without this charge, CILC customers who operate only off-peak would pay nothing for the transmission investment necessary to serve them.

[93] Order 8951-A, p. 2
[94] Order No. 18259, issued October 7, 1987, in Docket No. 861403-EG, In re: Petition of Florida Power and Light Company for Authority to Implement a Trial Commercial/Industrial Load Control Project, p1.
[95] Order No. 18259, p. 1.
[96] Order No. 22747, issued March 28, 1990, in Docket No. 891045, In re: Petition of Florida Power & Light Company for approval of a permanent Commercial/Industrial Load Control program eligible for energy conservation cost recovery.
[97] Order No. 18259, p. 3

All of the components shown on the CILC rate schedule are described in Order No. 22747, and reflect the cost incurred to provide service to CILC customers, based on their usage characteristics. There is no specific credit listed in the tariff; instead the total revenue used to design rates is reduced by the avoided cost, and the resulting rates reflect the cost for the type of service provided. As a result, the CILC customer is only paying for the services he uses.

FPL has continued to calculate the components of the CILC rate according to the method approved in Order 22747. The rates shown on MFR Schedule E-14, page 26 of 37, are consistent with the costs shown in MFR Schedule E-6b, unit costs for each rate schedule using the requested revenue requirements and Cost of Service Methodology. The total cost of providing service to the CILC class is $101,734,000 as shown in MFR Schedule E-1, Attachment 2, page 1. From that total allocated cost, FPL subtracted the avoided cost savings of ($19,670,000), which is collected through the Energy Conservation Cost Recovery Clause from all customers. Base rates were then designed on a revenue requirement of $82,064,000.

It is not clear how FIPUG witness Pollock derives the numbers used in his testimony to allege that there is a subsidy embedded in the CILC rate. However, it appears that the subsidy he alleges is simply the result of the increase in the base rate costs properly assigned to the class, based on its usage characteristics. The $30.6 million difference, which witness Pollock calls an improper subsidy, results from the base rate portion of the bill increasing while the avoided cost offset has not. Witness Pollock appears to assume that the avoided cost savings must increase by the same amount as the base rates, thus maintaining the relationship between the credit amount and the total class revenue requirement. There is no provision in the CILC rate design that requires this symmetry. The savings attributable to the CILC program are based on avoided costs. Witness Deaton noted that avoided costs will be reviewed in the Demand Side Management (DSM) proceedings. If avoided costs, or savings, attributable to the CILC program are increased in another proceeding, that will reduce the revenue requirements used to determine the CILC rates, and rates will correspondingly be reduced.[98] Until the amount of the avoided costs attributable to CILC load changes, however, reducing rates below the approved cost of service is not appropriate.

We find that FPL has properly calculated the CILC base rates, in accordance with our Order No. 22747.

Commercial/Industrial Demand Reduction Rider Credit

The Commercial/Industrial Demand Reduction Rider (CDR) credit is available to commercial or industrial customers eligible to participate in this optional load management program offered by FPL. The CDR program was first proposed by FPL in 1999 as part of its demand-side management plan to meet the numeric conservation goals we set for FPL in Order No. PSC-99-1942-FOF-EG. The proposed program included a monthly credit of $4.75 per kW based upon the difference between firm demand and total demand. We approved the CDR

[98] Specific credits for load management programs will be addressed in the implementation phase of Docket No. 080407-EQ, Commission review of numeric conservation goals (Florida Power& Light).

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program on May 8, 2000.[99] We again approved the program, including the CDR credit of $4.75 per kW, in 2004 when FPL submitted the conservation plans it was proposing to meet the goals we set in Docket No. PSC-04-0029-EG.[100] The CDR was subsequently reduced to $4.68 per kW when Gross Receipt Taxes previously embedded in base rates were removed as a result of the 2005 Settlement Order.[101]

FIPUG witness Pollock testified that the CDR credit should be increased from $4.68 to $5.50 per kW to reflect the increased cost of new generation and transmission capacity. The costs for new generation and transmission capacity are reflected in FPL's most recent Ten Year Site Plan. In its brief, FIPUG stated that FPL is projecting significant growth in non-firm load and that this load has been and is projected to be a valuable resource to FPL to serve firm load customers when needed. Witness Pollock explained that he arrived at the $5.50 figure by looking at FPL's avoided cost in their standard offer filing which showed a capacity need in 2021, projected the revenue requirements from that study, and then discounted those requirements back to the period of 2010 to 2012.

We note that FPL is required to submit estimates of the cost-effectiveness of any existing, new, or modified demand-side conservation programs per our Rule 25-17.0021(4)(j), F.A.C., Goals for Electric Utilities. Our Rule 25-17.008(3), F.A.C., prescribes the cost-effectiveness tests that must be performed by referencing the "Florida Public Service Commission Cost Effectiveness Manual For Demand Side Management Programs and Self-Service Wheeling Proposals" This manual requires three tests: (1) RIM test, (2) Participant test, and (3) Total Resource Costs test. None of these tests have been performed as part of this docket. They will be performed for all programs FPL submits to meet the new numeric conservation goals which are being set in Docket No. 080407-EG. FPL is required to submit any existing, new or modified programs it has designed to meet our approved goals. At that time, we will review the cost-effectiveness of the program, including costs and credits to customers such as the CDR credit. The CDR rider will receive a thorough review and evaluation of its cost-effectiveness then.

Customer participation in this demand reduction program is entirely voluntary. FPL is not seeking any changes to the CDR credit in this docket. The appropriate amount for the CDR credit can be addressed at the program implementation phase in the numeric conservation goals docket.[102] We set new numeric goals for FPL on December 2, 2009.[103] FPL is required to file programs designed to meet the goals we approved within 90 days following the final goals order, in accordance with Section 366.82(7), F.S., and Rule 25-17.0021(4), F.A.C.

[99] Order No. PSC-00-0915-PAA-EG, issued May 8, 2000, in Docket No. 991788-EG, In re: Approval of Demand-Side Management Plan of Florida Power & Light Company.
[100] Order No. PSC-06-0025-FOF-EG, issued January 10, 2006, in Docket No. 040029, In re: Petition for approval of numeric conservation goals by Florida Power & Light Company.
[101] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.
[102] Docket No. 080407-EG, In re: Commission review of numeric conservation goals (Florida Power & Light Company).
[103] Order No. PSC-09-0855-FOF-EG, issued on December 30, 2009, in Docket Nos. 080407-EQ – 080413-EG, In re: Commission review of numeric conservation goals.

Time of Use Rate Design

We first addressed time-of-use rates in 1978 when, under the requirements of PURPA, the Commission evaluated the standard relating to Peak Load Pricing. Order No. 9523 stated that the main purpose of peak load pricing is to promote economic efficiency.[104] In Order No. 9661, we ordered all investor-owned electric utilities to offer an optional time-of-use rate to all customers.[105] That order further set forth uniform definitions for on- and off-peak billing periods, establishing the two period rating still used today. It states that average incremental costs during on-peak and off-peak hours are used to allocated average fuel costs between on and off-peak periods and the system annual load factor is used to allocated demand cost components to on-peak and off-peak rating periods.

FPL has calculated demand rates based on demand costs as proposed in the Cost of Service Study. It proposed to use the same demand charge for both the standard rate and the corresponding time-of-use rate, with the time-of-use rate demand rate only applying to demand occurring in the on-peak period. Customers pay no demand charge for demand occurring in off-peak periods. The composite per unit demand cost for the General Service Demand classes is shown at $11.95, as noted by FIPUG witness Pollock. However, FPL then adjusts this number to arrive at different demand charges for each rate class. The proposed demand charges for each class are shown in MFR Schedule E-13C. Based on MFR Schedule E-14, Attachment 2 of 3, page 10 of 37, the unit cost was reduced by $2.00 across the board for all rate classes. FPL then made further adjustments to each class for what appears to be the decreasing proportion of distribution costs allocated the large classes, with the GSLDT-3 receiving the largest adjustment to reflect that this class is transmission level only.

We acknowledge witness Pollock's position that demand charges should reflect demand costs and energy charges should reflect energy costs. However, consideration of rate stability and rate shock are also important considerations in rate design. Increases in the demand charge impact low load factor customers to a greater extent than high load factor customers because they are less able to offset the higher demand costs with lower energy costs and are thus less able to affect their total bill. FPL's demand rates have not changed significantly in over twenty years and increasing demand charges to unit costs in one step might be too drastic and could disproportionately affect low load factor customers. For these reasons we agree with the method used by FPL to set demand rates for the GSD classes.

The purpose of time-of-use rates is to encourage customers to use capacity during off-peak hours. The differential between the on- and off-peak energy charge should establish a meaningful pricing signal. For all but the largest GSD class (GSLDT-3) FPL has reduced the differential between on- and off-peak rates, compared to existing rates. FPL began its calculations of the energy charge with the energy unit cost from the Cost of Service Study.

[104] Order No. 9385, issued May 20, 1980, in Docket Nos. 790793-EU, In re: Show Cause order to electric utilities concerning peak load pricing for general service customers, and 790859-EU, In re: General investigation into electric rate structures to see whether they tend to promote the conservation of energy.
[105] Order No. 9661, issued November 26, 1980, in Docket Nos. 790793-EU, In re: Show Cause order to electric utilities concerning peak load pricing for general service customers, and 790859-EU, In re: General investigation into electric rate structures to see whether they tend to promote the conservation of energy.

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From there, FPL adjusted the unit cost, using the class average on- and off-peak kWh ratios and establishing a break even rate with the otherwise applicable flat rate.

Similar to the design of the demand rates, FPL started with the energy unit cost for the class as described above, adjusting the calculated per kWh costs for both demand and energy. The end result is a reduction in the on-peak to off-peak ratio compared to existing rates. This makes time-of-use rates less advantageous to both customers and FPL. The customer saves less by shifting load to off-peak periods and loses less by operating during peak periods. If less load is shifted, any conservation impacts of reduced on peak demand of a time-of-use rate are diminished.

FPL failed to adequately explain how it arrived at the new rates, and has not provided adequate support for decreasing the differential between on- and off-peak energy rates. In Docket No. 910890-EI, we approved a formula for calculating time-of-use energy rates that sets the off-peak rate at the average system energy component from the cost of service study. In addition, in that order we stated that the on-peak charge will then be the result of a break even calculation with the standard rate, based on the class's (or combined classes') on-peak and off-peak energy consumption.[106] There is no evidence in this docket on what the impact would be to apply the strict formula used in the 910890-EI docket. However, it is reasonable, as a proxy, to maintain the current differential between on- and off-peak ratios to prevent unexpected impacts on existing time-of-use customers who have adapted their usage to this ratio. This results in differentials close to those advocated by FIPUG. Reducing the differential could negate investments in energy efficiency measures designed to move load off peak.

AFFIRM represents a coalition of quick-serve restaurants that have substantially similar electrical usage characteristics. Affirm Witness Klepper stated that AFFIRM members are economically disadvantaged because the pricing alternatives currently available to them do not reflect the economies of scale to FPL that result from the load characteristics of AFFIRM members. AFFIRM witness Klepper stated that AFFIRM members have a limited ability to respond to price signals because of the limited rate options available to them. Witness Klepper also noted that most of AFFIRM's members operate during system peak periods but use disproportionately lesser amounts of energy during FPL's defined on-peak periods and a disproportionately greater amount of energy during FPL's defined off-peak periods, compared to other commercial and industrial customers. FPL's Witness Deaton stated that, contrary to AFFIRM's contention that its customers are limited to the GSD and GSDT rate schedules, FPL offers many options, such as the high load factor time-of-use rate that may be beneficial. Witness Deaton contended that AFFIRM's members may not have adequately explored the options available to them, prior to requesting that FPL design a new rate.

AFFIRM did not propose a specific rate design; nor was there any discussion of the impacts on other customers of offering a new rate designed as AFFIRM would desire. In order to design a new rate FPL would need to identify the types of customers to be targeted, and determine what the specific load and cost characteristics of the proposed new sub-group of

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[106] Order No. PSC 92-1198-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In re: Petition for a Rate Increase by Florida Power Corporation.

customers would be. Assuming that existing customers would leave existing classes to take advantage of any new rate, FPL would also have to estimate the impact on existing rate classes (migration). None of that information was presented in this docket. As a result, we cannot design a specific new rate as AFFIRM has requested. Witness Deaton did state that FPL is willing to work with AFFIRM, or any of its customers to explore the benefits of the existing HLFT rates. We direct FPL to work with AFFIRM and its members to explore other options, such as multi-period pricing, which would address at least some of AFFIRM's concerns. This is consistent with the federal legislation cited by AFFIRM it is Brief.

We find that FPL's design of the time-of-use demand charges is appropriate. We direct FPL to design the energy charges to maintain the current ratio between on- and off-peak energy charges, in order to maintain the current incentive to use energy off peak. We also find that there is insufficient evidence in this docket to require FPL to design a new time-of-use rate for commercial customers. We direct FPL to work with AFFIRM, and any other parties who wish to participate, to design a new time-of-use option to address the concerns raised by AFFIRM, and report back to us no later than August 1, 2010, on the progress of such discussions.

Prepayment Option

This matter arose from customer testimony presented at the Ft. Myers service hearing. FPL witness Santos testified that during that hearing several customers were interested in a prepayment plan. The customers wished to pay an estimated yearly amount of their electric bill a year early, and receive a discount from FPL based on FPL's cost of capital. The customers would then in turn borrow money to pay their electric bills at a low cost to them, and thus save money.

Witness Santos testified that FPL has formed a team to evaluate the proposal. Witness Santos explained that FPL is willing to evaluate the proposal and come back to us early next year with the results of its evaluation. Witness Santos stated that FPL has to be certain that none of its other customers are jeopardized by the prepayment plan option, and it needs to establish what the appropriate discount rate is. Further, FPL may have to change its billing system to accommodate the prepayment plan. Witness Santos stated the FPL would report back to us by the second quarter of 2010.

In its brief, OPC stated that FPL should be required to provide a study evaluating the merits of a prepayment option in lieu of monthly billing within a month of the agenda conferences in this case. The concept of a prepayment plan first surfaced at the Ft. Myers service hearing, which took place on June 19, 2009. OPC stated that while FPL has created a team to look at the issue, FPL has not done much else and that this Commission should require more.

Witness Santos also stated that, prior to the Ft. Myers service hearing, a customer had communicated with FPL regarding a pre-payment plan. We agree that FPL has had time to evaluate the proposal, and therefore we direct FPL to provide a study to us evaluating the merits of a prepayment option in lieu of monthly billing no later than March 1, 2010.

We would expect that any prepayment option would be codified as a tariff, similar to the budget billing option. If the initial study results in a proposed tariff, the tariff would be brought before us for approval under normal tariff procedure, and parties could participate in the Agenda Conference at which the tariff would be discussed. If the study does not result in a proposed tariff, the study itself shall be brought before us to discuss what further actions, if any, are appropriate regarding this matter. We would expect that the study would be a collaborative effort involving all interested persons, who will have the opportunity to address the study when we consider it.

Nuclear Uprates

In Order No. PSC-09-0783-FOF-EI, issued on November 19, 2009, we approved FPL's Nuclear Cost Recovery Clause amounts for 2010.[107] All costs that FPL removed from its base rate revenue requirements were allowed in the NCRC for 2010. We approve FPL's proposal to transfer revenue, expenses and investments associated with nuclear uprates from base rates to the NCRC for the 2010 projected test year.

LED Street Lighting

This issue arose from testimony at the Plantation service hearing Lauderhill Mayor Richard Kaplan testified that his city received an energy block grant fund of $595,200 from the federal government to reduce energy consumption. Federal regulations governing use of the funds place a high priority on replacing conventional street lights with LED lights. Under FPL's existing tariff, however, the city would continue to pay the same rate even if it replaced existing lights with LED lights. According to Mayor Kaplan, energy usage can be reduced from 40 percent to 60 percent through the use of LED street lighting. Mayor Kaplan asked that we address the issue because of the difficulty he encountered trying to work with FPL on conservation programs.

FPL indicated that In March 2009, it installed LED street lights at its headquarters as a pilot program. FPL witness Spoor testified that it is his understanding that the energy consumption of the LED lights is less than the traditional light that is offered presently. Witness Spoor stated that LED lights are a newer technology, and that is why FPL is piloting them in the corporate parking lot. He testified that FPL will have to run the pilot for a year to understand everything about the technology. According to witness Spoor, FPL is studying how LED lights will function in high humidity, lightning, and rain.

There seems to be no dispute on this issue other than when FPL should be required to provide us a report on its pilot project. FPL stated in its brief that FPL would file the results of the pilot program by June 1, 2010. OPC stated in its brief that FPL should be required to provide a study by March 1, 2010. Since the City of Lauderhill and possibly other cities have an opportunity to save energy usage with LED lights, we agree that FPL should provide the study in a timely fashion, but we also believe that FPL should be given adequate time to fully analyze the

[107] Order No. PSC-09-0783-FOF-EI, issued on November 19, 2009, in Docket No. 090009-EI, In re: Nuclear cost recovery clause.

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performance of the LED lights. Therefore, we will establish the due date for submission of FPL's study of April 1, 2010. We will review the results of the study and determine what further actions, if any, FPL shall take on this matter.

RATES AND CHARGES

This section of our Order addresses the rates issues we considered at our January 29, 2010, rates Agenda Conference.

Based on the decisions we made at our January 13, 2010, revenue requirements Agenda, FPL filed a compliance cost of service study on January 18, 2010. The compliance cost of service study establishes the revenue requirement for each rate class, and final rates and charges.

As explained earlier, the appropriate method to allocate any revenue increase to the various rate classes, after recognizing any additional revenues realized in other operating revenues, is to track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes to parity as practicable. No rate class shall receive an increase greater than 1.5 times the system average percentage increase in total, and no class shall receive a decrease. The allocation of the rate increase is shown in Schedule 6. The current and approved rates and charges for all rate classes are shown in Schedule 7, pages 1 through 19.

Several interim steps are necessary to establish the allocation of the rate increase by rate class. First, FPL calculated present class operating revenues and the increase at parity. The increase at parity represents that target revenue requirements deficiency, i.e., the increase necessary to bring revenues from that rate class to the system rate of return. This is a calculation to establish a baseline for allocation of the increase to individual classes. The cost of service indicates that certain rate classes are currently earning above the system rate of return and should therefore be entitled to a revenue reduction. However, consistent with our decision that no class shall receive a decrease, FPL adjusted the increase needed to achieve parity for the other rate classes by this calculated revenue reduction of $58 million. This process establishes the initial revenue increase for each class. This initial increase must then be adjusted to account for the percentage increase limitation we have approved. The average system percentage increase is 0.8 percent. Consistent with our decision that no rate class shall receive an increase greater than 1.5 times the system average percentage increase in total, each class's percentage increase was limited to 1.2 percent (0.8% x 1.5 = 1.2%). The final revenue requirements by rate class are derived through an iterative process which repeatedly reallocates dollars so that all three constraints (movement towards parity, no decreases, and no increase greater than 1.5 percent of system average) are maximized. The percentage increase for all rate classes is shown in column 11 of Schedule 6.

The final step is to translate the class revenue requirement into actual rates. The revenue requirement for each rate class is first reduced by the customer charge revenues. Customer charges are set at the customer unit cost as derived from the cost of service study. The initial demand and energy charges are based on unit costs, and then adjusted to meet target group revenues and revenue neutrality with the time-of-use option.

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As mentioned previously, we denied FPL's proposed increase in its service charges, and therefore no additional revenues are achieved from service charges. We did approve a stipulation to approve an increase in the temporary service charges. That increase is reflected in the $222,000 total increase shown in column 5 of Schedule 6, and represents the only increase in service charge revenues.

Residential bill impacts.

Schedule 8 contains a calculation of FPL's 1,000 kilowatt-hours (kWh) monthly residential bill at both present and approved rates. As a result of this rate case, a residential customer who uses 1,000 kWh per month will see a $1.03 increase in the monthly bill. We note that in January 2010, the residential 1,000 kWh bill decreased by $15.29 primarily as a result of lower fuel costs. In addition, customers received a one-time refund on the electric bill in January 2010 as a result of our decision in the fuel docket.[108] The one-time refund for a residential customer using 1,000 kWhs was $44.46.

Schedule 8 also shows bill impacts at various other residential consumption levels. The amount of the increase decreases with increasing consumption levels. FPL's residential rates typically have been inverted rates with a one cent differential. That rate design has been in place since the 1970s. Inverted rates are set at a level to produce the same revenues as under a flat rate design while maintaining the one cent differential. In May 2007, FPL's base rates increased as a result of the Generation Base Rate Adjustment (GBRA) associated with the commercial operation of Turkey Point Unit 5. Pursuant to the 2005 Settlement Order, the GBRA was to be implemented by adjusting base rates by an equal percentage. Turkey Point Unit 5 resulted in a 3.271 percent GBRA factor. Applying the GBRA factor to FPL's residential energy charges resulted in the second tier energy charge to be more than one cent higher than the first tier energy charge. As shown on page 1 of Schedule 7, FPL has proposed to revert back to the one cent inversion, consistent with our original approved design. To achieve the residential target revenues, the resulting second tier energy charge is lower than the current energy charge, reducing the impact on large residential users.

The revised rates shall be effective for meter readings taken on or after March 1, 2010.

Customer Charges

Customer charges are flat fees assessed each month, regardless of the amount of energy (kilowatt hours) used. Utilities typically design and levy customer charges to recover specific accounts associated with meter reading, metering equipment, customer service, and bill processing. Customer charges differ by rate class, depending on the class of customer and the types of equipment used to provide service.

[108] Order No. PSC-09-0795-FOF-EI, issued December 2, 2009, in Docket No. 090001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

The appropriate customer charges are shown in Schedule 7. We grant our staff the authority to administratively approve the tariffs filed to implement the rates, charges, and credits presented in Schedule 7.

Demand and Energy Charges

In this section of the Order we address the appropriate methodology to design the demand and energy charges, as well as the appropriate final demand and energy charges. Since the demand and energy charges are set in combination to produce the class revenue requirements, we will discuss the methodology for both charges here.

FIPUG took issue with the way in which FPL calculated the demand and energy charges. Specifically, witness Pollock asserted that all demand related costs should be recovered through the demand charge and only energy related costs should be recovered through the energy charge. He asserted that FPL has underpriced the demand charge and overpriced the energy charge for both standard and time-of-use rates.

FPL Witness Deaton stated that following a strict unit rate for demand charges as proposed by Witness Pollock would distort the relationships between the general service demand classes, and make it difficult to achieve target revenue while maintaining time-of-use design goals and principals. Witness Deaton further stated that FPL made limited adjustments to the general service demand rates to maintain the appropriate relationships between rate schedules within the general service demand classes. Adjustments were also made to the energy charges for the purposes of meeting target revenue levels by rate class.

We agree with witness Pollock that demand charges should reflect demand costs and energy charges should reflect energy costs to the greatest extent possible. We must also consider rate stability and rate shock, however, in our decisions regarding rate design. Increases in the demand charge affect low load factor customers to a greater extent than high load factor customers, because they are less able to offset the higher demand costs with lower energy costs, and are thus less able to affect their total bill. FPL's demand rates have not changed significantly in over twenty years. Increasing demand charges to recover the full demand allocated costs could disproportionately affect low load factor customers.

We find that FPL's method of limited adjustments to the demand and energy unit cost to maintain the appropriate relationship between rate schedules is reasonable. We approve the demand charges shown in Schedule 7. We approve the energy charges also shown in Schedule 7. The energy charges were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

Lighting Rate Charges

We approve the appropriate lighting rate charges shown in Schedule 7.

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Standby and Supplemental Services (SST-1) Rate Schedule

We approve the charges under the SST-1 rate schedule as shown in Schedule 7. The charges are calculated consistent with our Order No. 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Interruptible Standby and Supplemental Services (ISST-1) Rate Schedule

We approve the charges under the ISST-1 rate schedule as shown in Schedule 7. The rates are calculated consistent with Commission Order No. 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's Petition for Rate Increase is hereby granted in part and denied in part as set forth more specifically in this Order. It is further

ORDERED that each of the findings and directives made in the body of this Order are hereby approved in every respect. It is further

ORDERED that all matters contained in the appendix, attachments, and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that the revised rates and charges shall become effective for meter readings made on or after March 1, 2010. It is further

ORDERED that Florida Power & Light Company shall file, within 90 days after the date of the Final Order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records that will be required as a result of the findings made in this docket. It is further

ORDERED that upon expiration of the period for appeal these dockets shall be closed.

By ORDER of the Florida Public Service Commission this 17th day of March, 2010.

ANN COLE
Commission Clerk

(S E A L)

LCB

CONCURRENCE AND DISSENT BY: CHAIRMAN ARGENZIANO

CONCURRENCE BY: COMMISSIONER SKOP

DISSENTS BY: COMMISSIONER EDGAR
COMMISSIONER KLEMENT

CHAIRMAN ARGENZIANO, concurring in part and dissenting in part:

I concur with the decisions of the majority with respect to Generation Base Rate Adjustment (GBRA), Corrective Reserve Measures, and Return on Equity (ROE), and dissent with respect to the Equity Ratio and the Appropriate Equity Ratio for Ratemaking Purposes.

I. Generation Base Rate Adjustment (GBRA)

Use of a Generation Base Rate Adjustment (GBRA) mechanism in this case would be gross error, because (1) the mechanism has been crudely transplanted to an inappropriate context; (2) use of GBRA removes important factors from the regulatory calculus that can lower recovery amounts in the future; and (3) it would trigger a sea-change in the Commission's procedure in rate cases without any guarantee of administrative cost advantage. Future Commissions should approach requests for GBRA or GBRA-like mechanisms with skepticism.

FPL has attempted to apply GBRA to an inappropriate context in an effort to create a power-plant cost recovery clause in disguise. Originally, GBRA was an element of a settlement agreement. The settlement agreement provided that FPL's retail base rates and base rate structure

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would be frozen for four years; no petition for any new surcharges to recover costs traditionally recovered in base rates would be permitted; there would be a revenue sharing plan between FPL and its customers; and other components. The GBRA mechanism was a modification of the freeze on base rates, and was created to allow FPL to recover cost plus profit for plants for which the Commission had approved a need determination and which would be placed in service during the period covered by the settlement agreement. GBRA should not be expanded beyond its original context.

GBRA would set recovery amounts for new plants at the peak of a utility's revenue requirement.[109] After setting the rate of recovery at the accounting high-tide line, GBRA removes important factors from the regulatory calculus that can lower the necessary recovery level on a forward basis. For instance, under GBRA ratepayers would no longer receive a corresponding benefit from FPL's declining costs from depreciation, effects of plant retirements, increased sales, and productivity improvements.[110] These same reasons were recognized when the Commission rejected TECO's proposal for a GBRA-like mechanism in a case earlier this year.[111] In that case the Commission noted that it would be inappropriate to consider "the cost of constructing new transmission facilities in isolation, without considering potential increases in revenues from additional sales or decreases in rate base due to retirements or depreciation that may offset the impact of construction costs."[112] The same reasoning applies today.

Adopting GBRA would constitute a sea-change in the Commission's approach without lowering administrative costs. While avoiding administrative costs is a valid goal, FPL failed to demonstrate that the cost of conducting a rate proceeding would outweigh potential reductions resulting from declines in rate base.[113] Moreover, certain benefits that the current procedure provides to *all* interested parties—examining a utility's entire cost of service to determine whether reductions in rate base may offset capital additions,[114] the level of detail provided, and the time available to make a decision on an important issue[115]—are unavailing under GBRA. Adopting GBRA would also change the relationship between interest groups: as witness Kollen noted, "[GBRA] provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of

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[109] TR 3115.

[110] EXH 485; TR 4268-4269.

[111] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Co.

[112] Id. at 127.

[113] TR 1266.

[114] TR 3731.

[115] The time period required for a traditional rate case proceeding differs from that required for need determination proceedings that the GBRA mechanism would utilize. Rate cases generally take at least eight months to complete and include five months devoted to discovery, in accordance with section 366.06, Florida Statutes (2009). Need determination proceedings, by contrast, must be completed within 135 days from the date a petition is filed. § 403.519(4), Fla. Stat. (2009).

increases in revenues and reductions in other costs."[116] In other words, current procedure sets the table with dishes equally before all interest groups, but GBRA would offer certain dishes exclusively to a utility company.

I suggest that future commissions approach requests for GBRA or GBRA-like mechanisms with skepticism. FPL already collects about 61% of its total costs through various "pass-through" mechanisms and cost-recovery clauses.[117] Fuel costs, environmental costs, conservation costs, and certain preconstruction costs for nuclear units are dealt with outside the base rate mechanism. The Commission authorized fuel cost recovery charges because the volatility in prices made the costs ill-suited for inclusion in base rates; for other costs, the legislature directed the Commission to permit recovery through special clauses. While there are often benefits to breaking decisions down into more manageable bites, at some point this can degenerate into piecemeal policy where regulators are buried in a series of discordant facts with no way to assess the system as a whole and allow all interested parties the chance to discuss the larger picture. Rate cases, for all their trouble, do provide an opportunity for assessment giving a clearer and more complete picture than a series of preordered recoveries.

II. Corrective Reserve Measures

FPL has over-collected depreciation expense by roughly $1.2 billion dollars. After applying a portion of that reserve surplus to offset unrecovered costs associated with capital recovery schedules, the Commission was left with $894 million dollars in depreciation reserve. The Commission, by unanimous vote, has correctly weighed the relevant factors,[118] and decided to amortize the entire $894 million dollar surplus over four years, in keeping with Commission policy regarding amortization as quickly as possible consistent with utility impact.

III. Return on Equity (ROE)

Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) set forth the standards for determining the rate of return for regulated enterprises. The authorized return for a public utility should be (1) commensurate with returns on investment in other companies of comparable risk, (2) sufficient to maintain the financial integrity of the company, and (3) sufficient to maintain its ability to attract capital under reasonable terms. Id. The Commission was presented with conflicting evidence regarding the

[116] TR 3732.

[117] TR 2421.

[118] There are three factors the Commission considers when deciding how to correct a depreciation reserve imbalance: (1) the size of the intergenerational inequity (the greater the inequity the more compelling the need to address the imbalance over a shorter period); (2) the state of the ratepayers and the impact the proposed remedy would have on them (current state of the economy, ability to absorb costs, etcetera); and (3) the state of the company and the impact the proposed remedy would have on them (will the company earn a fair return, would a rapid amortization adversely affect the company's financial integrity to a *significant* degree—one that would justify a departure from the Commission's precedent of rectifying reserve imbalances as quickly as possible).

proper rate of return for FPL. It is the Commission's prerogative to evaluate the evidence and accord whatever weight to the conflicting opinions it deems appropriate. United Tel. Co. of Fla. v. Mayo, 345 So. 2d 648, 654 (Fla. 1977); Shevin v. Yarborough, 274 So. 2d 505, 508-509 (Fla. 1973).

FPL's request for 12.5% ROE was exceedingly high when compared to returns on investment for other business undertakings with corresponding risks and uncertainties. I came to this conclusion because FPL is not a risky venture, because witness Woolridge's testimony was extremely creditable and more convincing than that of competing experts, and because FPL's "heightened risk" arguments were unconvincing. The evidence demonstrated that FPL's specific risk characteristics merit a lower point within the acceptable ranges of return on equity.

FPL is a monopoly earning a guaranteed profit by providing an essential service in an economic environment made virtually risk-free by legislative action. In fact, FPL already collects about 61% of its total costs through various "pass-through" mechanisms and cost-recovery clauses.[119] It runs essentially no risk for (i) costs related to storm events, per section 366.8260, Florida Statutes (2009); (ii) renewable energy undertakings, per section 366.91, Florida Statutes (2009); (iii) nuclear costs, per section 366.93, Florida Statutes (2009); (iv) recoveries for environmental compliance costs, per section 366.8295, Florida Statutes (2009); (v) conservation costs, per section 366.82, Florida Statutes (2009); (vi) fuel and capacity costs, per Commission orders.

Moreover, the reduction in risk from Florida's constructive regulatory environment is necessarily an element to consider when setting the return on equity for Florida firms. I would like to see this risk component reduced to a calculable formula, in order to more accurately adjust the returns of Florida firms when compared to returns on investment earned by comparable firms. I believe that the essentially risk free rate of treasury bills would serve as an appropriate comparator for the risk associated with the 60% of its costs which Florida utilities are guaranteed.[120]

The average authorized ROE by regulatory commissions across the country is 10.51%.[121] No state regulatory commission authorized an ROE of 12.5% from January 2009 to August 2009.[122] FPL filed for a 12.5% ROE and failed to make its case.

Dr. Avera was FPL's primary witness on the matter of ROE. Dr. Avera's non-utility proxy group was not helpful, in that setting the ROE is a utility-specific, factual determination. Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of West Virginia, 262 U.S.

[119] TR 2421.

[120] See also Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Co. (Commissioner Argenziano, dissenting) (concluding that it is difficult to see what risk exists for the utility in the conduct of its operations).

[121] EXH 462.

[122] Id.

679, 692 (1923); United Tel. Co. v. Mayo, 345 So. 2d 648 (Fla. 1977). As witnesses Woolridge and Baudino stated, there are multiple reasons why a non-utility proxy group is an inappropriate comparison for FPL.[123]

Indeed, witness Avera could only justify FPL's requested 12.5% ROE under the discounted cash flow method through heavy reliance upon a non-utility proxy group. The average indicated returns of the non-utility proxy group—composed of companies like Walmart and Walgreens, none of which are vertically integrated, regulated monopoly businesses[124]—came in at 12.9-13.4%.[125] In contrast, witness Avera's utility proxy group had a range of 10.6-11.5%.[126]

More to the point, competing witnesses offered more persuasive testimony than witness Avera, and there were significant flaws in witness Avera's methodology for his utility proxy group. Of the experts testifying on the matter of ROE, I was most convinced by witness Woolridge. His demeanor was more natural and his replies on cross-examination more responsive and credible than those of witness Avera, and his explanations demonstrated a thoroughness and attention to detail. For example, witness Woolridge examined data and used three criteria to establish a proxy group similar to FPL for his discounted cash flow analysis. One criterion required that a company receive a minimum of 70% of its total revenues from electric utility operations.[127] This criterion is significant because it screens out disparate firms—either in product or service provided, or in the dimensions of unregulated portions of the business. Witness Baudino had a similar requirement for his proxy group: the companies must have generated at least 50% of their revenues from regulated electric operations. By comparison a number of firms within witness Avera's utility proxy group included companies with electric revenues as little as 10%, 4%, and 22% of total revenues.[128]

There were other flaws in witness Avera's methodology. For one, witness Avera ignored dividend growth rates, resulting in inflated ROE calculations. No satisfactory explanation was provided for this oversight. (Witness Avera was not inclined to this mistake, however, when testifying in other jurisdictions.)[129] Second, witness Avera relied exclusively on growth rates projected by Wall Street analysts and Value Line.[130] Such estimates are inflated and biased.[131]

[123] TR 2623, 3254. Witness Baudino concluded that "using higher required returns from a group of unregulated companies is obviously unjustified, inflates FPL's required ROE, and should be rejected by the Commission." TR 2624.

[124] Witness Avera's non-utility group was composed of the 66 non-utility companies listed in Exhibit 138.

[125] TR 4424; EXH 138.

[126] EXH 136.

[127] TR 3201.

[128] TR 3253; EXH 220.

[129] TR 4512.

[130] TR 3255-56.

[131] TR 3255-59, 4510, 4512; EXH 493.

Third, witness Avera improperly included an adjustment for flotation costs.[132] This adjustment was not linked to any actual costs incurred.[133] Witness Baudino demonstrated that flotation costs are already included in current stock prices and that adding an adjustment amounts to a double recovery.[134]

A 10% ROE is sufficient to maintain the financial integrity of the company and its ability to attract capital under reasonable terms. Witness Lawton demonstrated that FPL will continue to demonstrate strong financial integrity consistent with a single-A rating.[135] In addition, FPL's high equity ratio allows it to continue to access the capital markets on favorable terms. The use of a more reasonable amount of debt leverage is indicated because currently FPL's equity ratio is too high and places an undeserved burden on ratepayers.

Besides the fact that FPL is not a risky venture and the testimony on balance supported 10% as the appropriate ROE for FPL, FPL's arguments for its "riskiness" were unconvincing. I address these arguments here so future Commissions need not:

a. FPL argues that it should receive a bump in its ROE because of "exemplary management." This is nonsense. FPL's management has a statutory duty to provide reliable service to customers. This duty does not change with the ROE approved by the Commission. Any insinuation otherwise—for instance, that FPL's management will not work as diligently and will oversee lower service quality without an added bump in ROE—is crass and an unfortunate reflection on management.

b. FPL's argument that it is entitled to a higher ROE because of its high reliance on nuclear generation is faulty. Accepting FPL's argument would allow a utility to deliberately take on energy production mechanisms that are perceived as risky in order to increase its ROE. Introducing this type of regulatory reward would inappropriately skew the decisions of utility companies. The status quo, where utilities rely upon a variety of methods of production and balance the overall risks of production in a portfolio of different methods, is preferable.[136] And the risk factor of reliance on nuclear generation is systemic to the industry and not unique to FPL, so investors' expectations regarding this factor have already been captured in the cost of equity models.[137]

c. FPL appears to take two positions with regard to Florida's growth. When the Commission has to make a need determination for new plants, Florida is booming and thousands

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[132] TR 2622.

[133] TR 2630.

[134] TR 2360-31.

[135] EXH 254; TR 2300-01.

[136] Moreover, the logical extension of FPL's argument cuts against the position held by the company on other matters because it would give outside entities greater influence over a utility's portfolio standards. Cf. Fla. SB 1154, § 1 (2009) (attempting to set clean energy portfolio standards).

[137] TR 4752-86, 5474-82.

are demanding electricity. When the Commission has to set ROE, FPL faces increased risk because of a slowdown in customer growth, with a customer count now down to levels last seen in July 2007. The Florida population is not so flexible. Predicting energy demand in Florida may be slightly more difficult than in other areas because of a more itinerant population, but it is not the significant risk factor that FPL paints it to be.

d. FPL argues that Florida's geographical location and exposure to adverse weather events are firm-specific risk factors that require FPL's ROE be set higher than other comparable utilities. The guaranteed recovery of prudently incurred storm costs per section 366.8260, Florida Statutes, eliminates any such risk. FPL provided excellent returns during the 2004 and 2005 storm seasons, when there were seven hurricanes and approximately $1.8 billion dollars in costs to restore electric transmission and distribution. This demonstrates the vacuity of FPL's argument. Also, as noted by witness Avera, to the extent that cost recovery clauses are prevalent across the industry, this risk factor has already been included in the cost of equity estimates for utility proxy groups.[138]

IV. Equity Ratio and the Appropriate Equity Ratio for Ratemaking Purposes

I dissent from the decision of the majority on this issue. The Commission should not utilize the 59.6% equity ratio suggested by FPL for ratemaking purposes because it excessively and unreasonably burdens ratepayers; differs in kind from the appropriate capital structure of utilities in FPL's peer group; and allows FPL to subsidize the activities of FPL Groups' unregulated affiliates on the backs of Florida's ratepayers. The Commission should have used either the 53.5% ratio recommended by witness Baudino, or the 54.4% ratio suggested by witness Woolridge, when setting FPL's equity ratio for ratemaking purposes.

Equity costs more than debt. A higher proportion of equity in a utility's capital structure results in higher rates. Using more debt increases risk but also reduces the utility's costs and thus the amounts charged to ratepayers. FPL's equity ratio is excessive and unreasonable, and results in rates that are unnecessarily high.[139] A 59.6% equity ratio is not needed to support FPL's credit rating.[140] If a utility uses excessive equity financing, a regulatory authority may impute a more reasonable capital structure for ratemaking purposes. See In re Northern States Power Co., 416 N.W.2d 719, 724-727 (Minn. 1987) (reasoning that the petitioning utility had the burden of proving the proposed rate is fair and reasonable, and, as a component of the rate base, that the capital structure debt-equity allocation is fair and just; concluding that when, in the Commission's judgment, a petitioning utility has failed to establish the reasonableness of costs which it claims justifies a proposed rate increase, the Commission may impute a hypothetical

[138] TR 4437-38, 4760-61.

[139] TR 2610. Cf. In re Northern States Power Co., 416 N.W.2d 719, 724-727 (Minn. 1987) (quoting with approval the Minnesota Public Utility Commission's decision stating: "The excessive equity ratio proposed by [the utility] for ratemaking purposes places an unreasonable burden on . . . ratepayers through an unnecessarily high cost of capital. The Commission agrees . . . that if . . . management chooses to maintain a higher than needed cost of equity ratio, then the shareholders, not [the utility's] customers, should pay the increased cost of capital.").

[140] TR 2611-12.

capital structure that will afford an ultimate determination of a reasonable and just rate); see also Citizens Utilities Co. v. Idaho Pub. Utilities Comm'n, 112 Idaho 1061, 739 P.2d 360 (1987) (affirming the Commission's decision adopting a hypothetical capital structure for ratemaking purposes, and noting that one of the rationales for adopting a hypothetical capital structure is to counter the effect of an "equity-thick utility" so that a Commission can achieve a proper balance between the interests of the utility investor and the utility ratepayer); Carnegie Natural Gas Co. v. Pa. Pub. Util. Comm'n, 61 Pa. Commw. 436, 433 A.2d 938 (1981) (stating that "[w]here a utility's actual capital structure is too heavily weighted on either the debt or equity side, the commission, which is responsible for determining a capital structure which allocates the cost of debt and equity in their proper proportions, must make adjustments to the utility's capital structure").[141] The Commission should do so here.

FPL's 59.6% equity ratio differs in kind from the appropriate capital structure of utilities. Two separate experts evaluating different peer groups that they independently compiled for comparability to FPL agreed on this.[142] The average equity ratio for witness Woolridge's peer group was roughly 42%.[143] The average equity ratio for witness Baudino's peer group was 47.6%.[144] FPL proposes a 59.6% equity ratio. This difference is a hole plugged with 100 million dollars a year from the pockets of ratepayers.

FPL's 59.6% equity ratio subsidizes the activities of the unregulated affiliates of FPL Group. FPL Group Capital is highly leveraged yet maintains an "A" credit rating; FPL Group could not do this without FPL's excessively high equity ratio.[145] This is because FPL Group can offset the high risk of one of its entities with the lower risk of another.[146] FPL Group Capital is (1) highly leveraged,[147] and (2) owns FPL Energy, which has high risk operations that detract from FPL Group's credit.[148] FPL is the counterweight. Allowing FPL its excessive equity ratio exposes ratepayers to the risk of subsidizing FPL Group's unregulated activities.[149]

The consequence of the Commission's decision is to allow a utility to retire debt and shore up its capital structure prior to a rate case, anticipating that this alteration—based on

[141] TR 3208.

[142] And a third expert, witness Pollock, agreed with them. Witness Pollock testified that FPL's equity ratio is much higher than the equity ratios of other electric utilities. TR 2961. In fact, at an equity ratio approaching 60 percent, FPL is one of the least leveraged regulated utilities in the nation. TR 2953-2954. He recommended that FPL's equity ratio be adjusted to put FPL in line with other electric utilities, and suggested a 50.2% equity ratio. TR 2961-2962.

[143] TR 3207.

[144] TR 2615.

[145] TR 2519.

[146] FPL Group's "A" credit rating is based on the consolidated credit profile of the company, including FPL and FPL Group Capital (which owns FPL Energy). TR 2586.

[147] TR 2519.

[148] TR 2586.

[149] TR 2619.

regulatory gamesmanship, not business judgment—will result in a windfall to shareholders, who will collect the difference in the returns between debt and equity. Here the difference amounts to $106 million dollars per year (comparing the 54.4% ratio suggested by witness Woolridge and the 59.6% ratio proposed by FPL). There is a reason not a single other regulatory commission in this country has authorized more than a 55% equity ratio for a utility's capital structure.[150]

COMMISSIONER SKOP, concurring specially with comment on Issue 120:

With respect to Issue 120 (Storm Damage Reserve Accrual), I concur with the majority and write separately to briefly articulate my basis for decision. The Florida Power & Light Company (FPL) storm damage reserve account is a funded reserve account. In simple terms, this means that any storm damage reserve funds collected from FPL ratepayers are actually deposited and held within a restricted storm damage account to offset actual storm damage costs at a future point in time when such costs may arise. In deciding this issue, it is important to recognize that the storm damage reserve accrual is ultimately a discretionary expenditure which increases the FPL revenue requirement on a dollar for dollar basis. In the instant case, suspending the storm damage reserve accrual is justified because the suspension of the storm damage reserve accrual reduces the overall FPL revenue requirement, the existing FPL storm damage reserve balance was approximately $184.8 million dollars[151] at the end of 2009, FPL customers are currently paying a surcharge for past storm costs, and the Commission has proven mechanisms to address the timely recovery of storm damage costs via surcharge or securitization should such action be necessary.[152]

In closing, there are opportunity costs and various tradeoffs involved in any decision. Given the prevailing economic conditions and the discretionary nature of the expense, the majority decision to suspend the storm damage reserve accrual was prudent. As with any discretionary expenditure, should economic conditions improve, I would support reinstating the

[150] No state regulatory commission authorized more than a 55% equity ratio for a utility's capital structure from January 2009 to August 2009. EXH 462.

[151] The existing FPL storm damage reserve balance of approximately $184.8 million dollars (MFR Schedule B-21) seems to provide an adequate measure of protection for FPL ratepayers based upon statistical analysis. In his direct testimony, witness Harris testified that there was only a 30.5 percent probability of having storm damages greater than $100 million dollars in any given year, and only a 18.0 percent probability of having storm damages greater than $200 million dollars in any given year. (EXH 127)

[152] See Order No. PSC-05-0937-FOF-EI, issued September 21, 2005, in Docket No. 041291-EI, In re: Petition for authority to recover prudently incurred storm restoration costs related to 2004 storm season that exceed storm reserve balance, by Florida Power & Light Company; Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.; Order No. PSC-06-0464-FOF-EI, issued May 30, 2006, in Docket No. 060038-EI, In re: Petition for issuance of a storm recovery financing order by Florida Power & Light Company.

FPL storm damage reserve accrual as necessary to achieve an appropriate storm damage reserve balance.

COMMISSIONER EDGAR, dissenting with the following opinion:

I respectfully dissent with the majority decision on Issue 120. FPL proposed to establish an annual accrual to the storm damage reserve. Our staff recommended in favor of an accrual but at a lesser amount. By a 3-2 vote, the majority voted to deny not only a lesser amount, but also went further and denied any annual accrual to a storm damage reserve. I disagree with this decision.

In Order No. PSC-93-0918-FOF-EI, the Commission authorized a self-insurance mechanism for storm damage. As discussed in Order No. PSC-09-0283-FOF-EI, our current overall regulatory framework for the recovery of storm damage costs consists of three major components: an annual storm accrual, a storm reserve adequate to accommodate most, but not all, storm years, and a provision for utilities to seek recovery of costs that go beyond the storm reserve. Section 366.8260, Florida Statutes, permits utilities to recover all reasonable and prudent expenses for storm damage. In dockets addressing the damages resulting from the 2004 and 2005 hurricane seasons, we heard from thousands of residents and businesses about the impact on their lives and their local economy when electricity was unavailable post-severe storm. We also heard testimony opposing imposition of a monthly surcharge at the very time families and businesses were attempting to recover from the costs that they had incurred from storm damage (damage to property, housing, loss of revenue, etc.).

I believe that a small annual accrual to support a healthy and reasonable reserve is an important and beneficial component of our state's storm preparedness.

COMMISSIONER KLEMENT dissents on Storm Damage Reserve and Service Charges, without opinion.

ATTACHMENT B

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT B

SCHEDULE 1

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2010 TEST YEAR

Issue No.		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Nuclear Fuel - No AFUDC (Net)	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	28,288,080,000	(12,590,521,000)	15,697,559,000	707,530,000	74,502,000	374,733,000	16,854,324,000	209,262,000	17,063,586,000
	Commission Adjustments:									
14	WCEC 3 - No GBRA	0	0	0	0	0	0	0	0	0
15	Transmission Investments and Costs	(386,896,000)	144,299,000	(242,597,000)	(18,623,000)	(4,200,000)	0	(265,420,000)	3,700,000	(261,720,000)
16	Jurisdictional Separation	0	0	0	0	0	0	0	0	0
42	Fossil Dismantlement Accrual	0	(1,320,284)	(1,320,284)	0	0	0	(1,320,284)	0	(1,320,284)
46	Cost Recovery Clause Over-Recovery	0	0	0	0	0	0	0	(101,971,000)	(101,971,000)
47	Advanced Metering Infrastructure	0	0	0	0	0	0	0	0	0
50	Plant in Service Level	(785,187,189)	460,387,189	(324,800,000)	0	0	0	(324,800,000)	0	(324,800,000)
51	Accumulated Depreciation	0	469,416,500	469,416,500	0	0	0	469,416,500	0	469,416,500
52	Florida EnergySecure Line	0	0	0	0	0	0	0	0	0
53-S	ECRC Capital Items	0	0	0	0	0	0	0	0	0
55	Construction Work in Progress	0	0	0	(1,264,000)	0	0	(1,264,000)	0	(1,264,000)
56	Property Held for Future Use	0	0	0	0	0	0	0	0	0
57-S	Fuel Inventories	0	0	0	0	0	0	0	0	0
58	Nuclear End of Life and Last Core	0	0	0	0	0	0	0	0	0
59	Nuclear Fuel in Rate Base	0	0	0	0	0	0	0	0	0
60	Nuclear Fuel Level	0	0	0	0	0	(3,771,000)	(3,771,000)	0	(3,771,000)
61	Glades Power Park Amortization	0	0	0	0	0	0	0	0	0
62	Working Capital Level	0	0	0	0	0	0	0	4,078,000	4,078,000
63	Total Rate Base	0	0	0	0	0	0	0	0	0
83	SJRPP Transfer to CCRC	0	0	0	0	0	0	0	0	0
94	Aviation Costs	(53,268,205)	27,853,907	(25,414,298)	0	0	0	(25,414,298)	0	(25,414,298)
108	Department of Energy Settlement	(25,866,000)	252,000	(25,614,000)	(828,000)	0	0	(26,442,000)	0	(26,442,000)
120	Storm Damage Reserve	0	0	0	0	0	0	0	0	0
122	Rate Case Expense	0	0	0	0	0	0	0	(2,948,000)	(2,948,000)
173	Nuclear Uprates	0	0	0	0	0	0	0	0	0
---	Total Commission Adjustments	(1,251,217,394)	1,100,888,312	(150,329,082)	(20,715,000)	(4,200,000)	(3,771,000)	(179,015,082)	(97,141,000)	(276,156,082)
63	Commission Adjusted Rate Base	27,036,862,606	(11,489,632,688)	15,547,229,918	686,815,000	70,302,000	370,962,000	16,675,308,918	112,121,000	16,787,429,918

ATTACHMENT B

SCHEDULE 2

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2010 TEST YEAR

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	8,178,980,000	47.93%	12.50%	5.99%
Long-term Debt	5,377,787,000	31.52%	5.55%	1.75%
Short-term Debt	161,857,000	0.95%	2.96%	0.03%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	564,652,000	3.31%	5.98%	0.20%
Deferred Income Taxes	2,723,327,000	15.96%	0.00%	0.00%
Tax Credits - Weighted Cost	56,983,000	0.33%	9.74%	0.03%
Total	17,063,586,000	100.00%		8.00%
Equity Ratio	59.62%			

Commission Adjusted	($) Amount	($) Specific Adjustments	($) Adjusted Total	Ratio	($) Pro Rata Adjustments	($) Staff Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	8,178,980,000	(305,580,000)	7,873,400,000	47.00%	16,567,199	7,889,967,199	47.00%	10.00%	4.70%
Long-term Debt	5,377,787,000	(89,953,000)	5,287,834,000	31.57%	11,126,654	5,298,960,654	31.57%	5.49%	1.73%
Short-term Debt	161,857,000	(6,071,000)	155,786,000	0.93%	327,805	156,113,805	0.93%	2.11%	0.02%
Preferred Stock	0	0	0	0.00%	0	0	0.00%	0.00%	0.00%
Customer Deposits	564,652,000	(21,084,000)	543,568,000	3.24%	1,143,775	544,711,775	3.24%	5.98%	0.19%
Deferred Income Taxes	2,723,327,000	162,847,000	2,886,174,000	17.23%	6,073,084	2,892,247,084	17.23%	0.00%	0.00%
Tax Credits - Weighted Cost	56,983,000	(51,565,000)	5,418,000	0.03%	11,401	5,429,401	0.03%	8.19%	0.00%
Total	17,063,586,000	(311,406,000)	16,752,180,000	100.00%	35,249,918	16,787,429,918	100.00%		6.65%
Equity Ratio	59.62%					59.12%			

Interest Synchronization Dollar Amount Change	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Long-term Debt	(78,826,346)	5.49%	(4,327,566)	38.575%	1,669,359
Short-term Debt	(5,743,195)	2.11%	(121,181)	38.575%	46,746
Customer Deposits	(19,940,225)	5.98%	(1,192,425)	38.575%	459,978
Tax Credits - Weighted Cost	(51,553,599)	8.19%	(4,221,210)	38.575%	1,628,332
					2,176,083
Cost Rate Change					
Long-term Debt	5,377,787,000	-0.06%	(3,226,672)	38.575%	1,244,689
Short-term Debt	161,857,000	-0.85%	(1,375,785)	38.575%	530,709
Tax Credits - Weighted Cost	56,983,000	-1.55%	(884,375)	38.575%	341,148
					2,116,545
TOTAL					4,292,628

ATTACHMENT B

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
NET OPERATING INCOME
DECEMBER 2010 TEST YEAR

SCHEDULE 3

Issue		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes and ITCs	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	4,114,727,000	27,505,000	1,694,367,000	1,074,265,000	350,370,000	243,338,000	(1,002,000)	3,388,844,000	725,883,000
No.	Commission Adjustments:									
3	2010 Customer, kWh & kW Forecast	0	0	0	0	0	0	0	0	0
7	2011 Customer, kWh & kW Forecast	0	0	0	0	0	0	0	0	0
14	WCEC 3 - No GBRA	0	0	0	0	0	0	0	0	0
15	Transmission Investments and Costs	(33,639,000)	0	(10,462,000)	(10,335,000)	(4,918,000)	(3,056,683)	0	(28,771,683)	(4,867,317)
16	Jurisdictional Separation	0	0	0	0	0	0	0	0	0
58	Nuclear End of Life and Last Core	0	0	(6,137,000)	0	0	2,367,348	0	(3,769,652)	3,769,652
61	Glades Power Park Amortization	0	0	0	0	0	0	0	0	0
82	Customer Growth and Inflation Factors	0	0	0	0	0	0	0	0	0
83	SJRPP Transfer to CCRC	0	0	0	0	0	0	0	0	0
84	FAC Revenues & Expenses	0	0	0	0	0	0	0	0	0
85	ECCR Revenues & Expenses	0	0	0	0	0	0	0	0	0
86	CCRC Revenues & Expenses	0	0	0	0	0	0	0	0	0
87	ECRC Revenues & Expenses	0	0	0	0	0	0	0	0	0
88	C/I Demand Reduction Rider	0	0	0	0	0	0	0	0	0
89	Late Payment Revenues	18,390,146	0	0	0	13,241	7,088,891	0	7,102,132	11,288,014
90	Revenue Forecast	36,969,000	0	0	0	26,618	14,250,524	0	14,277,142	22,691,858
91	Total Operating Revenues	0	0	0	0	0	0	0	0	0
92	Charitable Contibutions	0	0	0	0	0	0	0	0	0
93	Historical Museum	0	0	(45,470)	0	0	17,540	0	(27,930)	27,930
94	Aviation Costs	0	0	(1,633,916)	(2,092,009)	0	1,437,276	0	(2,288,649)	2,288,649
95	Advanced Metering Infrastructure	0	0	0	0	0	0	0	0	0
96	Bad Debt Expense	0	0	3,805,000	0	0	(1,467,779)	0	2,337,221	(2,337,221)
97	FAC Bad Debt Expense	0	0	16,893,000	0	0	(6,516,475)	0	10,376,525	(10,376,525)
98-S	Advertising Expenses	0	0	0	0	0	0	0	0	0
99-S	Lobbying Expenses	0	0	0	0	0	0	0	0	0
100	Unfilled Positions and Overtime	0	0	(15,392,467)	0	(882,729)	6,278,157	0	(9,997,039)	9,997,039
101	Productivity Improvements	0	0	0	0	0	0	0	0	0
102	Nuclear Production Staffing	0	0	0	0	0	0	0	0	0
103	Salaries and Employee Benefits	0	0	(49,510,136)	0	0	19,098,535	0	(30,411,601)	30,411,601
106	Pension Expense	0	0	0	0	0	0	0	0	0
107	Environmental Insurance Refund	0	0	0	0	0	0	0	0	0
108	Department of Energy Settlement	0	0	(6,084,000)	(747,000)	(109,000)	2,677,105	0	(4,262,895)	4,262,895
109	Affiliated Companies Transactions	0	0	(4,555,224)	0	(510,000)	1,953,910	0	(3,111,314)	3,111,314
116A	Gain on Sale	0	0	0	0	0	0	0	0	0
119	FPL-NED Assets	0	0	0	0	0	0	0	0	0
120	Storm Damage Accrual	0	0	(148,666,500)	0	0	57,348,102	0	(91,318,398)	91,318,398
121	Fossil Dismantlement Accrual	0	0	0	2,640,568	0	(1,018,599)	0	1,621,969	(1,621,969)
122	Rate Case Expense	0	0	(217,250)	0	0	83,804	0	(133,446)	133,446
123-S	Atrium	0	0	0	0	0	0	0	0	0
124	ECCR Payroll in Base Rates	0	0	1,582,000	0	0	(610,257)	0	971,744	(971,744)
125	CCRC Payroll in Base Rates	0	0	427,000	0	0	(164,715)	0	262,285	(262,285)
126	Hedging Costs in FAC	0	0	650,000	0	0	(250,738)	0	399,263	(399,263)
127-S	Orange Grove Operations	0	0	0	0	0	0	0	0	0
128	Level of O&M Expenses	0	0	0	0	0	0	0	0	0
129	Customer Information System	0	0	0	(435,000)	0	167,801	0	(267,199)	267,199
130	Capital Expenditures Reduction	0	0	0	0	0	0	0	0	0
131	Depreciation Expense	0	0	0	(310,060,000)	0	119,605,645	0	(190,454,355)	190,454,355
132	Taxes Other Than Income	0	0	0	0	972,000	(374,949)	0	597,051	(597,051)
133	American Recovery & Reinvestment Ac	0	0	0	0	0	0	0	0	0
134	Income Tax Expense	0	0	0	0	0	0	0	0	0
173	Nuclear Uprates	0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	4,292,628	0	4,292,628	(4,292,628)
	Total Commission Adjustments	21,720,146	0	(219,346,963)	(321,028,441)	(5,407,870)	223,207,072	0	(322,576,202)	344,296,348
135	Commission Adjusted NOI	4,136,447,146	27,505,000	1,475,020,037	753,236,559	344,962,130	466,545,072	(1,002,000)	3,066,267,798	1,070,179,348

ATTACHMENT B

SCHEDULE 4

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
DECEMBER 2010 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) Commission Adjusted
1	Revenue Requirement	100.000	100.000
2	Gross Receipts Tax	0.000	0.000
3	Regulatory Assessment Fee	(0.072)	(0.072)
4	Bad Debt Rate	(0.260)	(0.302)
5	Net Before Income Taxes	99.668	99.626
6	Income Taxes (Line 5 x 38.575%)	38.447	38.431
7	Revenue Expansion Factor	61.221	61.195
8	Net Operating Income Multiplier (100%/Line 7)	1.63342	1.63411

ATTACHMENT B

SCHEDULE 5

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
DECEMBER 2010 PROJECTED TEST YEAR
OPERATING REVENUE INCREASE CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$ 17,063,586,000	$16,787,429,918
2.	Overall Rate of Return	8.00%	6.65%
3.	Required Net Operating Income (1)x(2)	1,364,748,000	1,116,364,090
4.	Achieved Net Operating Income	725,883,000	1,070,179,348
5.	Net Operating Income Deficiency (3)-(4)	638,865,000	46,184,742
6.	Net Operating Income Multiplier	1.63342	1.63411
7.	Operating Revenue Increase (5)x(6)	$1,043,535,000	$75,470,948

ATTACHMENT B

SCHEDULE 6

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
ALLOCATION OF THE RATE INCREASE BY RATE CLASSES
(in $000)

Line No.	(1) Rate Class	(2) Present ROR	(3) Present Index	(4) Present Class Operating Revenue	(5) Increase from Service Charges	(6) Increase from Sale of Electricity	(7) Increase from Unbilled	(8) Total Increase	(9) Approved ROR	(10) Approved Index		(11) % Increase With Adjustment Clauses	(12) % Increase Without Adjustment Clauses
1	CILC-1D	4.68%	73%	73,071	0	2,448	-12	2,436	5.10%	77%		1.2%	3.3%
2	CILC-1G	7.11%	112%	6,031	0	83	-1	82	7.33%	110%		0.6%	1.4%
3	CILC-1T	4.82%	76%	25,572	0	1,071	-4	1,067	5.40%	81%		1.2%	4.2%
4	CS1	5.82%	91%	5,149	0	90	-1	89	6.04%	91%		0.6%	1.7%
5	CS2	5.76%	90%	1,950	0	10	0	10	5.83%	88%		0.2%	0.5%
6	GS1	8.59%	135%	306,675	20	3,270	-65	3,226	8.79%	132%		0.5%	1.1%
7	GSCU-1	10.38%	163%	1,569	0	19	0	19	10.66%	160%		0.5%	1.2%
8	GSD1	6.08%	95%	767,469	4	22,900	-172	22,732	6.49%	98%		1.2%	3.0%
9	GSLD1	4.35%	68%	146,931	0	3,544	-32	3,512	4.63%	70%		0.9%	2.4%
10	GSLD2	4.73%	74%	21,730	0	110	-4	106	4.80%	72%		0.2%	0.5%
11	GSLD3	6.02%	95%	4,612	0	198	-1	197	6.67%	100%		1.2%	4.3%
12	HLFT1	5.30%	83%	35,996	0	224	-7	216	5.38%	81%		0.2%	0.6%
13	HLFT2	3.27%	51%	119,909	0	4,559	-26	4,533	3.68%	55%		1.2%	3.8%
14	HLFT3	3.32%	52%	24,433	0	675	-5	670	3.62%	54%		0.8%	2.7%
15	MET	5.64%	89%	2,906	0	86	-1	86	6.04%	91%		1.2%	2.9%
16	OL-1	19.42%	305%	12,057	0	68	-3	66	19.66%	296%		0.4%	0.5%
17	OS-2	3.59%	56%	912	0	21	0	21	3.83%	58%		1.2%	2.3%
18	RS1	6.65%	104%	2,469,818	197	35,147	-522	34,822	6.88%	103%		0.7%	1.4%
19	SDTR-1	5.78%	91%	15,912	0	495	-4	492	6.20%	93%		1.2%	3.1%
20	SDTR-2	4.06%	64%	16,143	0	499	-4	496	4.41%	66%		1.1%	3.1%
21	SDTR-3	3.08%	48%	1,754	0	26	0	26	3.23%	49%		0.5%	1.5%
22	SL-1	10.36%	163%	70,632	0	459	-15	444	10.50%	158%		0.4%	0.6%
23	SL-2	11.98%	188%	1,147	0	16	0	16	12.29%	185%		0.5%	1.4%
24	SST-DST	4.79%	75%	265	0	8	0	8	5.14%	77%		1.2%	3.0%
25	SST-TST	19.08%	300%	3,807	0	105	-1	104	19.90%	299%		1.0%	2.7%
26													
27													
28	Total	6.37%	100%	4,136,447	222	76,131	-882	75,471	6.65%	100%		0.8%	1.8%
29											1.5x	1.2%	
30											Max	1.2%	
31													
32	**Notes:**												
33	Certain general service demand level classes do not receive the maximum increase in order to maintain relationships between the related rate classes												
34	No rate increase should exceed 1.5x the system average percentage increase in total, i.e. with adjustment clauses, and no class should receive a decrease												
35	TOTALS MAY NOT ADD DUE TO ROUNDING												

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
RS-1	Residential Service			
	Customer Charge/Minimum	$5.69		$5.90
	Base Energy Charge (¢ per kWh)			
	First 1,000 kWh	3.631		3.711
	All additional kWh	4.733		4.711
RST-1	Residential Service -Time of Use			
	Customer Charge/Minimum	$9.04		$16.04
	with $160.45 Lump-sum metering payment made prior to January 1, 2010	$5.69		
	with $608.40 Lump-sum metering payment effective January 1, 2010			$5.90
	Base Energy Charge (¢ per kWh)			
	On-Peak	7.618		7.734
	Off-Peak	2.338		2.454
GS-1	General Service - Non Demand (0-20 kW)			
	Customer Charge/Minimum			
	Metered	$9.08		$6.89
	Unmetered	$6.04		$0.89
	Base Energy Charge (¢ per kWh)	4.189		4.427
GST-1	General Service - Non Demand - Time of Use (0-20 kW)			
	Customer Charge/Minimum	$12.42		$13.53
	with $160.45 Lump-sum metering payment made prior to January 1, 2010	$9.08		
	with $398.40 Lump-sum metering payment effective January 1, 2010			$6.89
	Base Energy Charge (¢ per kWh)			
	On-Peak	8.189		8.453
	Off-Peak	2.361		2.625

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
GSD-1	General Service Demand (21-499 kW)			
	Customer Charge	$35.31		$16.44
	Demand Charge ($/kW)	$5.44		$6.50
	Base Energy Charge (¢ per kWh)	1.485		1.382
GSDT-1	General Service Demand - Time of Use (21-499 kW)			
	Customer Charge	$41.87		$22.77
	with $390.51 Lump-sum metering payment made prior to January 1, 2010	$35.31		
	with $379.80 Lump-sum metering payment effective January 1, 2010			$16.44
	Demand Charge - On-Peak ($/kW)	$5.44		$6.50
	Base Energy Charge (¢ per kWh)			
	On-Peak	3.466		3.102
	Off-Peak	0.953		0.635
GSLD-1	General Service Large Demand (500-1999 kW)			
	Customer Charge	$41.37		$50.13
	Demand Charge ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)	1.175		0.903
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)			
	Customer Charge	$41.37		$50.13
	Demand Charge - On-Peak ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.328		2.028
	Off-Peak	0.707		0.407

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
CS-1	Curtailable Service (500-1999 kW)			
	Customer Charge	$111.00		$50.13
	Demand Charge ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)	1.176		0.903
	Monthly Credit ($ per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09
CST-1	Curtailable Service -Time of Use (500-1999 kW)			
	Customer Charge	$111.00		$50.13
	Demand Charge - On-Peak ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.329		2.028
	Off-Peak	0.707		0.407
	Monthly Credit (per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09
GSLD-2	General Service Large Demand (2000 kW +)			
	Customer Charge	$171.54		$179.19
	Demand Charge ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)	1.172		0.845

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$171.54		$179.19
	Demand Charge - On-Peak ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.445		1.496
	Off-Peak	0.661		0.604
CS-2	Curtailable Service (2000 kW +)			
	Customer Charge	$171.54		$179.19
	Demand Charge ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)	1.172		0.845
	Monthly Credit (per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09
CST-2	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$171.54		$179.19
	Demand Charge - On-Peak ($/kW)	$6.30		$7.60
	Base Energy Charge (¢ per kWh)			
	On-Peak	2.449		1.496
	Off-Peak	0.661		0.604
	Monthly Credit (per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
GSLD-3	General Service Large Demand (2000 kW +)			
	Customer Charge	$403.63		$1,441.88
	Demand Charge ($/kW)	$6.30		$6.32
	Base Energy Charge (¢ per kWh)	0.609		0.624
GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)			
	Customer Charge	$403.63		$1,441.88
	Demand Charge - On-Peak ($/kW)	$6.30		$6.32
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.678		0.723
	Off-Peak	0.543		0.588
CS-3	Curtailable Service (2000 kW +)			
	Customer Charge	$403.63		$1,441.88
	Demand Charge ($/kW)	$6.30		$6.32
	Base Energy Charge (¢ per kWh)	0.609		0.624
	Monthly Credit (per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
CST-3	Curtailable Service -Time of Use (2000 kW +)			
	Customer Charge	$403.63		$1,441.88
	Demand Charge - On-Peak ($/kW)	$6.30		$6.32
	Base Energy Charge (¢ per kWh)			
	On-Peak	0.678		0.723
	Off-Peak	0.543		0.588
	Monthly Credit (per kW)	($1.72)		($1.72)
	Charges for Non-Compliance of Curtailment Demand			
	Rebilling for last 12 months (per kW)	$1.72		$1.72
	Penalty Charge-current month (per kW)	$3.70		$3.70
	Early Termination Penalty charge (per kW)	$1.09		$1.09
OS-2	Sports Field Service [Schedule closed to new customers]			
	Customer Charge	$9.08		$97.28
	Base Energy Charge (¢ per kWh)	6.233		4.874
MET	Metropolitan Transit Service			
	Customer Charge	$216.95		$373.94
	Base Demand Charge ($/kW)	$10.54		$9.28
	Base Energy Charge (¢ per kWh)	0.477		0.826

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
CILC-1	Commercial/Industrial Load Control Program [Schedule closed to new customers]			
	Customer Charge			
	(G) 200-499kW	$605.45		$122.00
	(D) above 500kW	$605.45		$175.00
	(T) transmission	$3,229.09		$1,866.00
	Base Demand Charge ($/kW)			
	per kW of Max Demand All kW:			
	(G) 200-499kW	$2.39		$3.20
	(D) above 500kW	$2.46		$3.17
	(T) transmission	None		None
	per kW of Load Control On-Peak:			
	(G) 200-499kW	$1.13		$1.32
	per kW of Load Control On-Peak:			
	(D) above 500kW	$1.17		$1.35
	(T) transmission	$1.16		$1.29
	Per kW of Firm On-Peak Demand			
	(G) 200-499kW	$4.84		$6.92
	(D) above 500kW	$5.91		$7.12
	(T) transmission	$6.30		$6.79
	Base Energy Charge (¢ per kWh)			
	On-Peak			
	(G) 200-499kW	1.046		1.160
	(D) above 500kW	0.727		0.631
	(T) transmission	0.536		0.585
	Off-Peak			
	(G) 200-499kW	1.046		1.160
	(D) above 500kW	0.727		0.631
	(T) transmission	0.536		0.585
	Excess "Firm Demand"			
	¤ Up to prior 60 months of service	Difference between Firm and Load-Control On-Peak Demand Charge		Difference between Firm and Load-Control On-Peak Demand Charge
	¤ Penalty Charge per kW for each month of rebilling	$0.99		$0.99

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
CDR	Commercial/Industrial Demand Reduction Rider			
	Monthly Rate			
	Customer Charge	Otherwise Applicable Rate		Otherwise Applicable Rate
	Demand Charge	Otherwise Applicable Rate		Otherwise Applicable Rate
	Energy Charge	Otherwise Applicable Rate		Otherwise Applicable Rate
	Monthly Administrative Adder			
	GSD-1	$570.14		$570.14
	GSDT-1	$563.58		$563.58
	GSLD-1, GSLDT-1	$564.07		$564.07
	GSLD-2, GSLDT-2	$433.91		$433.91
	GSLD-3, GSLDT-3	$2,825.46		$2,825.46
	HLFT	Applicable General Service Level Rate		Applicable General Service Level Rate
	SDTR	Applicable General Service Level Rate		Applicable General Service Level Rate
	Utility Controlled Demand Credit $/kW	-$4.68		-$4.68
	Excess "Firm Demand"	$4.68		$4.68
	¤ Up to prior 60 months of service			
	¤ Penalty Charge per kW for each month of rebilling	$0.99		$0.99
SL-1	Street Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$3.91		$3.91
	Sodium Vapor 9,500 lu 100 watts	$3.98		$3.98
	Sodium Vapor 16,000 lu 150 watts	$4.11		$4.11
	Sodium Vapor 22,000 lu 200 watts	$6.22		$6.22
	Sodium Vapor 50,000 lu 400 watts	$6.29		$6.29
	* Sodium Vapor 12,800 lu 150 watts	$4.27		$4.27
	* Sodium Vapor 27,500 lu 250 watts	$6.61		$6.61
	* Sodium Vapor 140,000 lu 1,000 watts	$9.95		$9.95
	* Mercury Vapor 6,000 lu 140 watts	$3.09		$3.09
	* Mercury Vapor 8,600 lu 175 watts	$3.13		$3.13
	* Mercury Vapor 11,500 lu 250 watts	$5.23		$5.23
	* Mercury Vapor 21,500 lu 400 watts	$5.21		$5.21
	* Mercury Vapor 39,500 lu 700 watts	$7.37		$7.37
	* Mercury Vapor 60,000 lu 1,000 watts	$7.54		$7.54

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
SL-1	Street Lighting (continued))			
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.50		$1.17
	Sodium Vapor 9,500 lu 100 watts	$1.51		$1.18
	Sodium Vapor 16,000 lu 150 watts	$1.54		$1.20
	Sodium Vapor 22,000 lu 200 watts	$1.98		$1.55
	Sodium Vapor 50,000 lu 400 watts	$1.95		$1.53
	* Sodium Vapor 12,800 lu 150 watts	$1.72		$1.35
	* Sodium Vapor 27,500 lu 250 watts	$2.09		$1.63
	* Sodium Vapor 140,000 lu 1,000 watts	$3.83		$3.00
	* Mercury Vapor 6,000 lu 140 watts	$1.36		$1.06
	* Mercury Vapor 8,600 lu 175 watts	$1.36		$1.06
	* Mercury Vapor 11,500 lu 250 watts	$1.96		$1.53
	* Mercury Vapor 21,500 lu 400 watts	$1.92		$1.50
	* Mercury Vapor 39,500 lu 700 watts	$3.26		$2.55
	* Mercury Vapor 60,000 lu 1,000 watts	$3.18		$2.49
	Energy Non-Fuel			
	Sodium Vapor 5,800 lu 70 watts	$0.65		$0.79
	Sodium Vapor 9,500 lu 100 watts	$0.92		$1.11
	Sodium Vapor 16,000 lu 150 watts	$1.34		$1.63
	Sodium Vapor 22,000 lu 200 watts	$1.97		$2.39
	Sodium Vapor 50,000 lu 400 watts	$3.75		$4.57
	* Sodium Vapor 12,800 lu 150 watts	$1.34		$1.63
	* Sodium Vapor 27,500 lu 250 watts	$2.59		$3.15
	* Sodium Vapor 140,000 lu 1,000 watts	$9.19		$11.17
	* Mercury Vapor 6,000 lu 140 watts	$1.39		$1.69
	* Mercury Vapor 8,600 lu 175 watts	$1.72		$2.09
	* Mercury Vapor 11,500 lu 250 watts	$2.32		$2.83
	* Mercury Vapor 21,500 lu 400 watts	$3.58		$4.35
	* Mercury Vapor 39,500 lu 700 watts	$6.08		$7.39
	* Mercury Vapor 60,000 lu 1,000 watts	$8.60		$10.46
	Total Charge-Fixtures, Maintenance & Energy			
	* Incandescent 1,000 lu 103 watts	$7.61		$7.78
	* Incandescent 2,500 lu 202 watts	$7.87		$8.21
	* Incandescent 4,000 lu 327 watts	$9.22		$9.78
	* Incandescent 6,000 lu 448 watts	$10.27		$11.03
	* Incandescent 10,000 lu 690 watts	$12.37		$13.55

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
SL-1	Street Lighting (continued))			
	Charge for Customer-Owned Units			
	Relamping and Energy			
	Sodium Vapor 5,800 lu 70 watts	$1.41		$1.38
	Sodium Vapor 9,500 lu 100 watts	$1.69		$1.72
	Sodium Vapor 16,000 lu 150 watts	$2.11		$2.23
	Sodium Vapor 22,000 lu 200 watts	$2.74		$3.16
	Sodium Vapor 50,000 lu 400 watts	$4.54		$5.35
	* Sodium Vapor 12,800 lu 150 watts	$2.37		$2.37
	* Sodium Vapor 27,500 lu 250 watts	$3.40		$3.96
	* Sodium Vapor 140,000 lu 1,000 watts	$11.00		$12.98
	* Mercury Vapor 6,000 lu 140 watts	$2.15		$2.28
	* Mercury Vapor 8,600 lu 175 watts	$2.49		$2.69
	* Mercury Vapor 11,500 lu 250 watts	$3.15		$3.47
	* Mercury Vapor 21,500 lu 400 watts	$4.37		$4.97
	* Mercury Vapor 39,500 lu 700 watts	$7.80		$7.43
	* Mercury Vapor 60,000 lu 1,000 watts	$9.69		$11.31
	* Incandescent 1,000 lu 103 watts	$2.70		$2.87
	* Incandescent 2,500 lu 202 watts	$3.49		$3.83
	* Incandescent 4,000 lu 327 watts	$4.54		$5.10
	* Incandescent 6,000 lu 448 watts	$5.48		$6.24
	* Incandescent 10,000 lu 690 watts	$7.54		$8.72
	* Fluorescent 19,800 lu 300 watts	$3.73		$4.32
	* Fluorescent 39,600 lu 700 watts	$7.20		$8.47
	Energy Only			
	Sodium Vapor 5,800 lu 70 watts	$0.65		$0.79
	Sodium Vapor 9,500 lu 100 watts	$0.92		$1.11
	Sodium Vapor 16,000 lu 150 watts	$1.34		$1.63
	Sodium Vapor 22,000 lu 200 watts	$1.97		$2.39
	Sodium Vapor 50,000 lu 400 watts	$3.75		$4.57
	* Sodium Vapor 12,800 lu 150 watts	$1.34		$1.63
	* Sodium Vapor 27,500 lu 250 watts	$2.59		$3.15
	* Sodium Vapor 140,000 lu 1,000 watts	$9.19		$11.17
	* Mercury Vapor 6,000 lu 140 watts	$1.39		$1.69
	* Mercury Vapor 8,600 lu 175 watts	$1.72		$2.09
	* Mercury Vapor 11,500 lu 250 watts	$2.32		$2.83
	* Mercury Vapor 21,500 lu 400 watts	$3.58		$4.35
	* Mercury Vapor 39,500 lu 700 watts	$6.08		$7.39
	* Mercury Vapor 60,000 lu 1,000 watts	$8.60		$10.46
	* Incandescent 1,000 lu 103 watts	$0.80		$0.98
	* Incandescent 2,500 lu 202 watts	$1.59		$1.93

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE	
SL-1	Street Lighting (continued))					
	* Incandescent 4,000 lu 327 watts		$2.59		$3.15	
	* Incandescent 6,000 lu 448 watts		$3.53		$4.29	
	* Incandescent 10,000 lu 690 watts		$5.45		$6.63	
	* Fluorescent 19,800 lu 300 watts		$2.72		$3.32	
	* Fluorescent 39,600 lu 700 watts		$5.91		$7.19	
	Non-Fuel Energy (¢ per kWh)		2.235		2.718	
	Other Charges					
	Wood Pole		$2.80		$2.80	
	Concrete Pole		$3.85		$3.85	
	Fiberglass Pole		$4.55		$4.55	
	Underground conductors not under paving (¢ per foot)		2.10		2.10	
	Underground conductors under paving (¢ per foot)		5.14		5.14	
	Willful Damage					
	Cost for Shield upon second occurrence		$120.00		$280.00	
PL-1	Premium Lighting					
	Present Value Revenue Requirement Multiplier		1.1605		1.4094	
	Monthly Rate					
	Facilities (Percentage of total work order cost)					
	10 Year Payment Option		1.380%		1.565%	*
	20 Year Payment Option		0.969%		1.038%	*
	Maintenance		FPL's estimated cost of maintaining facilities		FPL's estimated cost of maintaining facilities	
	Termination Factors					
	10 Year Payment Option					
		1	1.1605		1.4094	*
		2	0.9949		1.2216	*
		3	0.9184		1.1198	*
		4	0.8349		1.0108	*
		5	0.7440		0.8941	*
		6	0.6450		0.7692	*

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE		(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE	
PL-1	Premium Lighting (continued)					
		7	0.5371		0.6355	*
		8	0.4196		0.4924	*
		9	0.2915		0.3393	*
		10	0.1520		0.1754	*
	>10		0.0000		0.0000	*
	20 Year Payment Option					
		1	1.1605		1.4094	*
		2	1.0443		1.2848	*
		3	1.0215		1.2505	*
		4	0.9966		1.2139	*
		5	0.9695		1.1746	*
		6	0.9400		1.1326	*
		7	0.9079		1.0876	*
		8	0.8729		1.0395	*
		9	0.8347		0.9880	*
		10	0.7931		0.9328	*
		11	0.7478		0.8738	*
		12	0.6985		0.8107	*
		13	0.6447		0.7431	*
		14	0.5862		0.6707	*
		15	0.5224		0.5933	*
		16	0.4528		0.5104	*
		17	0.3771		0.4217	*
		18	0.2946		0.3268	*
		19	0.2047		0.2252	*
		20	0.1067		0.1164	*
		>20	0.0000		0.0000	*
	Non-Fuel Energy (¢ per kWh)		2.235		2.718	
	Willful Damage All occurrences after initial repair		Cost for repair or replacement		Cost for repair or replacement	
* 10 and 20 year payment options closed to new facilities						
RL-1	Recreational Lighting [Schedule closed to new customers]					
	Non-Fuel Energy (¢ per kWh)		Otherwise applicable General Service Rate		Otherwise applicable General Service Rate	
	Maintenance		FPL's estimated cost of maintaining facilities		FPL's estimated cost of maintaining facilities	

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(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
OL-1	Outdoor Lighting			
	Charges for FPL-Owned Units			
	Fixture			
	Sodium Vapor 5,800 lu 70 watts	$4.48		$4.49
	Sodium Vapor 9,500 lu 100 watts	$4.59		$4.59
	Sodium Vapor 16,000 lu 150 watts	$4.75		$4.75
	Sodium Vapor 22,000 lu 200 watts	$6.91		$6.91
	Sodium Vapor 50,000 lu 400 watts	$7.35		$7.35
	* Sodium Vapor 12,000 lu 150 watts	$5.08		$5.10
	* Mercury Vapor 6,000 lu 140 watts	$3.45		$3.45
	* Mercury Vapor 8,600 lu 175 watts	$3.47		$3.47
	* Mercury Vapor 21,500 lu 400 watts	$5.68		$5.68
	Maintenance			
	Sodium Vapor 5,800 lu 70 watts	$1.50		$1.03
	Sodium Vapor 9,500 lu 100 watts	$1.51		$1.03
	Sodium Vapor 16,000 lu 150 watts	$1.54		$1.05
	Sodium Vapor 22,000 lu 200 watts	$1.98		$1.36
	Sodium Vapor 50,000 lu 400 watts	$1.95		$1.34
	* Sodium Vapor 12,000 lu 150 watts	$1.72		$1.20
	* Mercury Vapor 6,000 lu 140 watts	$1.36		$0.93
	* Mercury Vapor 8,600 lu 175 watts	$1.36		$0.93
	* Mercury Vapor 21,500 lu 400 watts	$1.92		$1.31
	Energy Non-Fuel			
	Sodium Vapor 5,800 lu 70 watts	$0.65		$0.85
	Sodium Vapor 9,500 lu 100 watts	$0.92		$1.20
	Sodium Vapor 16,000 lu 150 watts	$1.34		$1.76
	Sodium Vapor 22,000 lu 200 watts	$1.97		$2.58
	Sodium Vapor 50,000 lu 400 watts	$3.76		$4.92
	* Sodium Vapor 12,000 lu 150 watts	$1.34		$1.76
	* Mercury Vapor 6,000 lu 140 watts	$1.39		$1.82
	* Mercury Vapor 8,600 lu 175 watts	$1.72		$2.26
	* Mercury Vapor 21,500 lu 400 watts	$3.58		$4.69

ATTACHMENT B

(1) CURRENT RATE SCHEDULE		(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
OL-1		Outdoor Lighting (continued)			
		Charges for Customer Owned Units			
		Total Charge-Relamping & Energy			
		Sodium Vapor 5,800 lu 70 watts	$1.41		$0.97
		Sodium Vapor 9,500 lu 100 watts	$1.70		$1.16
		Sodium Vapor 16,000 lu 150 watts	$2.11		$1.44
		Sodium Vapor 22,000 lu 200 watts	$2.73		$1.88
		Sodium Vapor 50,000 lu 400 watts	$4.54		$3.12
	*	Sodium Vapor 12,000 lu 150 watts	$2.37		$1.65
	*	Mercury Vapor 6,000 lu 140 watts	$2.15		$1.47
	*	Mercury Vapor 8,600 lu 175 watts	$2.49		$1.70
	*	Mercury Vapor 21,500 lu 400 watts	$4.37		$2.98
		Energy Only			
		Sodium Vapor 5,800 lu 70 watts	$0.65		$0.85
		Sodium Vapor 9,500 lu 100 watts	$0.92		$1.20
		Sodium Vapor 16,000 lu 150 watts	$1.34		$1.76
		Sodium Vapor 22,000 lu 200 watts	$1.97		$2.58
		Sodium Vapor 50,000 lu 400 watts	$3.76		$4.92
	*	Sodium Vapor 12,000 lu 150 watts	$1.34		$1.76
	*	Mercury Vapor 6,000 lu 140 watts	$1.39		$1.82
	*	Mercury Vapor 8,600 lu 175 watts	$1.72		$2.26
	*	Mercury Vapor 21,500 lu 400 watts	$3.58		$4.69
		Non-Fuel Energy (¢ per kWh)	2.238		2.931
		Other Charges			
		Wood Pole	$3.51		$3.51
		Concrete Pole	$4.72		$4.72
		Fiberglass Pole	$5.55		$5.55
		Underground conductors excluding Trenching per foot	$0.017		$0.017
		Down-guy, Anchor and Protector	$2.04		$2.04
SL-2		Traffic Signal Service			
		Base Energy Charge (¢ per kWh)	3.648		3.700
		Minimum Charge at each point	$2.88		$2.88

ATTACHMENT B

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
SST-1	Standby and Supplemental Service			
	Customer Charge			
	SST-1(D1)	$136.23		$75.13
	SST-1(D2)	$136.23		$75.13
	SST-1(D3)	$196.78		$204.19
	SST-1(T)	$428.86		$1,451.71
	Distribution Demand $/kW Contract Standby Demand			
	SST-1(D1)	$2.16		$2.61
	SST-1(D2)	$2.53		$4.31
	SST-1(D3)	$2.22		$2.38
	SST-1(T)	N/A		N/A
	Reservation Demand $/kW			
	SST-1(D1)	$0.80		$0.86
	SST-1(D2)	$0.79		$0.86
	SST-1(D3)	$0.79		$0.86
	SST-1(T)	$0.77		$1.03
	Daily Demand (On-Peak) $/kW			
	SST-1(D1)	$0.37		$0.41
	SST-1(D2)	$0.36		$0.41
	SST-1(D3)	$0.36		$0.41
	SST-1(T)	$0.36		$0.29
	Supplemental Service			
	Demand	Otherwise Applicable Rate		Otherwise Applicable Rate
	Energy	Otherwise Applicable Rate		Otherwise Applicable Rate
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	SST-1(D1)	0.754		0.612
	SST-1(D2)	0.774		0.612
	SST-1(D3)	0.765		0.612
	SST-1(T)	0.692		0.627
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	SST-1(D1)	0.754		0.612
	SST-1(D2)	0.774		0.612
	SST-1(D3)	0.765		0.612
	SST-1(T)	0.692		0.627

ATTACHMENT B

SCHEDULE 7
Page 16 of 19

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
ISST-1	Interruptible Standby and Supplemental Service			
	Customer Charge			
	Distribution	$630.68		$200.00
	Transmission	$3,254.33		$1,891.00
	Distribution Demand			
	Distribution	$2.46		$2.59
	Transmission	N/A		N/A
	Reservation Demand-Interruptible			
	Distribution	$0.17		$0.18
	Transmission	$0.15		$0.16
	Reservation Demand-Firm			
	Distribution	$0.79		$0.83
	Transmission	$0.77		$0.81
	Supplemental Service			
	Demand	Otherwise Applicable Rate		Otherwise Applicable Rate
	Energy	Otherwise Applicable Rate		Otherwise Applicable Rate
	Daily Demand (On-Peak) Firm Standby			
	Distribution	$0.36		$0.38
	Transmission	$0.36		$0.38
	Daily Demand (On-Peak) Interruptible Standby			
	Distribution	$0.07		$0.07
	Transmission	$0.07		$0.07
	Non-Fuel Energy - On-Peak (¢ per kWh)			
	Distribution	0.762		0.631
	Transmission	0.536		0.585
	Non-Fuel Energy - Off-Peak (¢ per kWh)			
	Distribution	0.762		0.631
	Transmission	0.536		0.585
	Excess "Firm Standby Demand"			
	¤ Up to prior 60 months of service	Difference between reservation charge for firm and interruptible standby demand times excess demand		Difference between reservation charge for firm and interruptible standby demand times excess demand
	¤ Penalty Charge per kW for each month of rebilling	$0.99		$0.99

ATTACHMENT B

SCHEDULE 7
Page 17 of 19

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
WIES-1	Wireless Internet Electric Service			
	Non-Fuel Energy (¢ per kWh)	19.326		38.877
	Minimum ten internet device delivery points with monthly energy usage not less than 20kWh or more than 50kWh per device.			
TR	Transformation Rider			
	Transformer Credit			
	(per kW of Billing Demand)	($0.39)		($0.24)
GSCU-1	General Service constant Usage			
	Customer Charge:	$10.08		$6.00
	Non-Fuel Energy Charges:			
	Base Energy Charge*	2.613		3.430
	* The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh			
HLFT-1	High Load Factor - Time of Use			
	Customer Charge:			
	21 - 499 kW:	$41.87		$22.77
	500 - 1,999 kW	$41.37		$50.13
	2,000 kW or greater	$171.54		$179.19
	Demand Charges:			
	On-peak Demand Charge:			
	21 - 499 kW:	$7.50		$7.83
	500 - 1,999 kW	$7.49		$7.83
	2,000 kW or greater	$7.49		$7.83
	Maximum Demand Charge:			
	21 - 499 kW:	$1.60		$1.81
	500 - 1,999 kW	$1.65		$1.81
	2,000 kW or greater	$1.62		$1.81
	Non-Fuel Energy Charges: (¢ per kWh)			
	On-Peak Period			
	21 - 499 kW:	1.697		1.179
	500 - 1,999 kW	0.533		0.527
	2,000 kW or greater	0.533		0.497

ATTACHMENT B

SCHEDULE 7
Page 18 of 19

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
	Off-Peak Period			
	21 - 499 kW:	0.533		0.635
	500 - 1,999 kW	0.533		0.527
	2,000 kW or greater	0.533		0.497
SDTR	Seasonal Demand – Time of Use Rider			
	Option A			
	Customer Charge:			
	21 - 499 kW:	$35.31		$22.77
	500 - 1,999 kW	$41.37		$50.13
	2,000 kW or greater	$171.54		$179.19
	Demand Charges:			
	Seasonal On-peak Demand:			
	21 - 499 kW:	$6.08		$7.70
	500 - 1,999 kW	$6.70		$8.55
	2,000 kW or greater	$6.70		$9.00
	Non-seasonal Demand Max Demand:			
	21 - 499 kW:	$5.12		$5.58
	500 - 1,999 kW	$6.09		$7.26
	2,000 kW or greater	$6.09		$7.22
	Energy Charges (¢ per kWh):			
	Seasonal On-peak Energy:			
	21 - 499 kW:	4.287		5.608
	500 - 1,999 kW	3.281		3.614
	2,000 kW or greater	3.273		2.949
	Seasonal Off-peak Energy:			
	21 - 499 kW:	1.133		0.952
	500 - 1,999 kW	0.896		0.622
	2,000 kW or greater	0.893		0.582
	Non-seasonal Energy			
	21 - 499 kW:	1.485		1.382
	500 - 1,999 kW	1.175		0.903
	2,000 kW or greater	1.172		0.845

ATTACHMENT B

(1) CURRENT RATE SCHEDULE	(2) TYPE OF CHARGE	(3) CURRENT RATE	(4) RATE SCHEDULE	(5) COMMISSION APPROVED RATE
SDTR	Seasonal Demand – Time of Use Rider (continued)			
	Option B			
	Customer Charge:			
	21 - 499 kW:	$41.87		$22.77
	500 - 1,999 kW	$41.37		$50.13
	2,000 kW or greater	$171.54		$179.19
	Demand Charges:			
	Seasonal On-peak Demand:			
	21 - 499 kW:	$6.08		$7.70
	500 - 1,999 kW	$6.70		$8.55
	2,000 kW or greater	$6.70		$9.00
	Non-seasonal On-peak Demand:			
	21 - 499 kW:	$5.12		$5.58
	500 - 1,999 kW	$6.09		$7.26
	2,000 kW or greater	$6.09		$7.22
	Energy Charges (¢ per kWh):			
	Seasonal On-peak Energy:			
	21 - 499 kW:	4.287		5.608
	500 - 1,999 kW	3.281		3.614
	2,000 kW or greater	3.273		2.949
	Seasonal Off-peak Energy:			
	21 - 499 kW:	1.133		0.952
	500 - 1,999 kW	0.896		0.622
	2,000 kW or greater	0.893		0.582
	Non-seasonal On-peak Energy:			
	21 - 499 kW:	3.466		3.107
	500 - 1,999 kW	2.328		1.865
	2,000 kW or greater	2.445		1.718
	Non-seasonal Off-peak Energy:			
	21 - 499 kW:	0.953		0.952
	500 - 1,999 kW	0.707		0.622
	2,000 kW or greater	0.661		0.582

SCHEDULE 8

FLORIDA POWER & LIGHT COMPANY
Docket No. 080677-EI
Monthly 1,000 Kilowatt-Hour Residential Electric Bill

	Current	Effective March 1, 2010	Increase/ (Decrease)
Customer Charge	$5.69	$5.90	$0.21
Energy Charge	$36.31	$37.11	$0.80
Fuel and Purchased Power	$38.57	$38.57	$0.00
Energy Conservation Cost Recovery	$1.88	$1.88	$0.00
Environmental Cost Recovery	$1.79	$1.79	$0.00
Capacity Cost Recovery	$6.21	$6.21	$0.00
Storm Cost Recovery Surcharge	$2.59	$2.59	$0.00
Gross Receipts Taxes	$2.39	$2.41	$0.02
Total Monthly Bill	**$95.43**	**$96.46**	**$1.03**

Florida Power & Light Company
Total Residential Bill Comparisons by kWh Usage

Usage	Current	Effective March 1, 2010	Difference From Current $	Difference From Current %
1,000 kWh	$95.43	$96.46	$1.03	1.1%
1,250 kWh	$123.21	$124.19	$0.98	0.8%
1,500 kWh	$151.01	$151.93	$0.92	0.6%
2,000 kWh	$206.57	$207.38	$0.81	0.4%
2,500 kWh	$262.15	$262.85	$0.70	0.3%
3,000 kWh	$317.72	$318.31	$0.59	0.2%

ATTACHMENT B

Appendix A

STIPULATIONS

At the prehearing, the parties reached stipulations on several issues. At the commencement of the hearing, we voted on, and approved, those stipulations. The stipulations previously approved by us are listed below. The stipulations fall within one of two categories, as listed below. "Category 1" stipulations reflect the agreement of FPL, our staff, and all of the intervenors in this docket. "Category 2" stipulations reflect the agreement of FPL and our staff where no other party has taken a position on the issue. Issues 123 and 127 are also classified as Category 2 stipulations, although some, but not all, intervenors agreed with FPL and our staff.

CATEGORY 1 STIPULATIONS:

ISSUE 54: Should FPL be permitted to record in rate base the incremental difference between Allowance for Funds Used During Construction (AFUDC) permitted by Section 366.93, F.S. for nuclear construction and FPL's most currently approved AFUDC for recovery when the nuclear plants enter commercial operation?

PARTIES: The parties agree that this issue will be decided in a different docket.

CATEGORY 2 STIPULATIONS:

The following issues have been agreed to by some parties. All other parties took no position.

ISSUE 123: Should an adjustment continue to be made to Administrative and General Expenses to eliminate "Atrium Expenses" per Order No. 10306, Docket No. 810002-EU?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

POSITION: No. the atrium has been retired and the adjustment is no longer necessary.

ISSUE 127: Should the Commission adjustment in FPL's 1985 base rate case, Docket No. 830465-EI, for imputed revenues associated with orange groves be reversed?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

PARTIES: Yes. The adjustment is no longer necessary as FPL leases the property and has included the lease revenue in operating revenues.

ATTACHMENT B

For the following issues, staff agrees with the FPL's position, and all other parties took no position. Accordingly, there are no factual issues in dispute.

ISSUE 53: Has FPL removed any Environmental Cost Recovery Clause (ECRC) capital cost recovery items from the ECRC and placed them into rate base?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

POSITION: No. FPL has not removed any ECRC capital cost recovery items from the ECRC and placed them in base rates.

ISSUE 57: Should any adjustments be made to FPL's fuel inventories?

POSITION: No. Subject to the adjustments listed on FPL witness Ousdahl's Exhibit KO-16, the 2010 and 2011 projections of FPL's fuel inventories are appropriate.

ISSUE 98: Should an adjustment be made to advertising expenses?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

POSITION: No. An adjustment is not necessary as advertising expenses included in 2010 and 2011 are utility related and informational, educational or related to consumer safety

ISSUE 99: Has FPL made the appropriate adjustments to remove lobbying expenses?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

POSITION: FPL has reflected the amounts applicable to lobbying expenses below the line for the projected test year 2010 and for the subsequent test year 2011. Therefore, no adjustment to remove lobbying expenses from net operating income is required.

ISSUE 143: Has FPL properly adjusted revenues to account for unbilled revenues?

POSITION: Yes. The appropriate adjustment to account for the increase in unbilled revenue is that shown in MFR E-12.

ISSUE 146: Are FPL's proposed Temporary Service Charges appropriate? (4.030)

POSITION: Yes. The appropriate Temporary/Construction Service Charges, as shown in MFR E-14, Attachment 1, are: (1) for Overhead: $255; and (2) for Underground: $142.

ISSUE 147: Is FPL's proposed increase in the charges to obtain a Building Efficiency Rating System (BERS) rating appropriate? (4.041)

POSITION: Yes. FPL has properly calculated the proposed charges for providing BERS audits pursuant to Florida Administrative Code Rule 25-17.003 (4) (a).

ISSUE 149: Are FPL's proposed charges under the Street Lighting Vandalism Option notification appropriate? (8.717)

POSITION: Yes. The appropriate charge, as shown in MFR-E-14, Attachments 1 and 3, is $279.98.

ISSUE 151: Is FPL's proposal to close the Wireless Internet Rate (WIES) schedule to new customers appropriate?

POSITION: Yes. As outlined in the current WIES tariff FPL is authorized to petition the Commission to close the WIES rate schedule if the kWh under the rate schedule have not reached 360,000 kWh by June 2004. For the twelve month period ending June 2009, kWh sales under the WIES have only reached 20,640 kWh.

ISSUE 153: Should FPL's proposal to remove the 10 year and 20 year payment options from the PL-1 and RL-1 tariff be approved? (8.720 and 8.743)

POSITION: Yes. Removing this option will avoid collection issues that often occur when the original customer requesting the payment option (e.g., a developer) transfers payment responsibility to another party (e.g., a homeowner's association).

ISSUE 158: Is FPL's proposed minimum charge for non-metered service under the GS rate appropriate?

POSITION: Yes, the proposed minimum charge for non-metered service under the GS rate appropriately reflects the difference between the GS customer charge and the metering costs for serving GS-1 customers.

ISSUE 176: Should FPL be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

POSITION: Yes.

ATTACHMENT B

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: 06/15/2023

TO: Office of Commission Clerk

FROM: Bureau of Consumer Assistance, Office of Consumer Assistance & Outreach

RE: Customer Correspondence

Please add the attached customer correspondence to Docket Correspondence-Consumers and their Representatives, in Docket 20230023.

ATTACHMENT C

Carla Barrington-Johnson

From:	Roger Goodman <roger.goodman@gmail.com>
Sent:	Thursday, June 15, 2023 8:38 AM
To:	Carla Barrington-Johnson
Subject:	Re: Florida Public Service Commission

TECO Peoples Gas
Tampa, Florida

Roger Goodman 517-349-2604

On Wed, Jun 14, 2023 at 4:25 PM Carla Barrington-Johnson <CBarring@psc.state.fl.us> wrote:

June 14, 2023

Dear Roger Goodman,

This email is in response to your recent inquiry to the Florida Public Service Commission (FPSC) regarding your gas/utility provider.

It would be beneficial if you could provide the following information:

- The name of the Utility in question

- A telephone number where the customer can be reached

You may send this information to me by reply e-mail or at the address and/or fax number listed below.

Sincerely,

John Plescow

Office of Consumer Assistance and Outreach

contact@psc.state.fl.us

Toll Free - 800-342-3552

Toll Free Fax 800-511-0809

ATTACHMENT C

2540 Shumard Oak Blvd.

Tallahassee, FL 32399

Note: Florida has a very broad public records law. Most written communications to or from state officials regarding state business are considered to be public records and will be made available to the public and the media upon request. Therefore, your e-mail message may be subject to public disclosure.

ATTACHMENT C

Roger Goodman
1746 Benzinger Ct.
The Villages, Florida 32162-1641
roger.goodman@gmail.com
Meter number AIX05149
Account #: 211007213013

Public Service Commission
Office of the Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Proposed changes in gas rates

Dear PSC,

I realize that there is inflation and gas prices must increase, However there is one price increase that I feel is unjustified:

RS-1 Monthly meter charge from $15.10 to $19.95

That amounts to an annual charge of $239.40 just to have a gas connection only, and does not include any gas usage. I believe this is an undue burden to the people living near the poverty level and the older retired folks living in Florida.

Please consider not approving this particular price increase.

Thanks,

Roger Goodman

RECEIVED
JUN 14 2023
FLORIDA PUBLIC SER. ...MISSION
CONSUMER ASSISTANCE

ATTACHMENT C

Darius Robinson

From:	John Plescow
Sent:	Friday, June 16, 2023 2:06 PM
To:	Consumer Correspondence; Consina Griffin-Greaux
Subject:	FW: To Clerk's office - RE: Rate increases

Please, add to dockets 20230001, 20230006, and 20230023.

-----Original Message-----
From: Consina Griffin-Greaux <CGriffin@psc.state.fl.us> On Behalf Of Consumer Contact
Sent: Friday, June 16, 2023 9:43 AM
To: John Plescow <JPlescow@PSC.STATE.FL.US>
Subject: To Clerk's office - RE: Rate increases

Hello John,

To Clerks office.

Thanks
Consina

-----Original Message-----
From: Terry Duncan <terry_reliancepools@yahoo.com>
Sent: Thursday, June 15, 2023 2:39 PM
To: Consumer Contact <Contact@PSC.STATE.FL.US>
Subject: Rate increases

Dear Public Services committee,
You can not allow these companies to increase rates. Families are struggling to buy food, water, electricity and gas. These companies are making millions and at the same time destroying the lives of working families across the state. Sunshine water, Duke Energy and TECO gas can not be allowed to crush what little stability we have left. We have been forced to make cuts in every aspect of our lives and we are running out of things to cut. Please spare Floridas families from further destruction.

Sincerely,
Terry Duncan
117 Hickory Tree Road
Longwood, FL 32750

Sent from my iPhone

ATTACHMENT C

Darius Robinson

From: John Plescow
Sent: Monday, June 19, 2023 9:22 AM
To: Consumer Correspondence; Consina Griffin-Greaux
Subject: FW: proposed Rate hike for Peoples Gas

Please, add to docket 20230023.

From: Consina Griffin-Greaux <CGriffin@psc.state.fl.us> **On Behalf Of** Consumer Contact
Sent: Monday, June 19, 2023 8:26 AM
To: John Plescow <JPlescow@PSC.STATE.FL.US>
Subject: RE: proposed Rate hike for Peoples Gas

John,

Please send to clerk's office. I am awaiting your response. Case# 1423455C, I will add the notes once I receive an email back from you.

Thanks

Consina

From: Bill Koch <outlook_4BFAB8325019B438@outlook.com>
Sent: Saturday, June 17, 2023 10:10 AM
To: Consumer Contact <Contact@PSC.STATE.FL.US>
Subject: proposed Rate hike for Peoples Gas

Dear Sirs:
I am in total opposition to the Peoples Gas System(TECO) proposed rate hike.
William C. Koch
9452 SW 93rd Loop
Ocala, Fl. 34481

Sent from Mail for Windows

ATTACHMENT C

CORRESPONDENCE
6/21/2023
DOCUMENT NO. 03725-2023

Roger Bonner
766 Jollymon Way
Daytona Beach FL 32124
P – 386-236-9313

Office of Commission Clerk
2540 Shumard Oak Blvd
Tallahassee FL 32399-0850

June 15, 2023

RECEIVED-FPSC
2023 JUN 21 AM 9: 53
COMMISSION CLERK

RE: Docket Number 20230023-GU

Dear Sir or Madam:

Teco People's Gas has submitted a Rate Increase Request.

I use very little natural gas in my home, usually less than $10.00 total monthly. Under their rate increase request my Customer Charge will increase from $15.10 per month to $19.95 per month. This increase amounts to a **32% increase** and is an unreasonable increase considering the small amount of natural gas I consume each month.

If you approve this rate increase request my total bill will be $10.00 for natural gas and a $19.95 Customer Charge – making my total bill $29.95 – but – of that amount – **over 66%** of my bill represents the proposed new customer charge. This is exuberant and troublesome.

I respectfully request you NOT approve this substantial increase in the Customer Charge for the smaller users of 0-99 Annual Therm Usage as it puts an undue burden on their smallest of customers.

Thank you for your kind consideration – be assured it is very much appreciated !!

Respectfully,

Roger Bonner

ATTACHMENT C

RAISE ON CUSTOMER CHARGE ?

G. Fouquet
2131 Alameda Ave.
Sarasota, FL 34234

CORRESPONDENCE
6/22/2023
DOCUMENT NO. 03744-2023

How the Proposed Changes in Rates and Charges May Impact Your Bill

The following tables show how the proposed rates and service charges compare with what you pay today.

Rate Class	Annual Therm Usage	Current Monthly Rates		Proposed Monthly Rates		
		Customer Charge	Base Rate	Customer Charge	Base Rate	
RS-1	0 - 99	$ 15.10	$ 0.27011	32% $ 19.95	$ 0.36738	4.85
RS-2	100 - 249	$ 18.10	$ 0.27011	41% $ 25.50 41%	$ 0.36738	7.4
RS-3	250 - 1,999	$ 24.60	$ 0.27011	34% $ 32.95	$ 0.36738	8.35
RS-GHP	N/A	$ 24.60	$ 0.09598	$ 32.95	$ 0.12950	
RSG (Residential Standby Generator)	< 19 therms > 20 therms	$ 23.91 $ 23.91	$ 0.00000 $ 0.27011	$ 32.95 $ 32.95	$ 0.29500 $ 0.29500	

Miscellaneous Service Charges	Current	Proposed
Residential Meter Turn On	$63.00 ($29.00 per additional meter)	$78.00 ($34.00 per additional meter)
Residential Meter Reconnect	$87.00 ($28.00 per additional meter)	$104.00 ($33.00 per additional meter)
Account Opening	$24.00	$33.00
Temporary Turn-off Charge	$30.00 per meter	$33.00 per meter
Failed Trip Charge	$25.00	$25.00
Trip Charge/Premise Collection	$25.00	$29.00

If approved, the proposed rates and service charges would be effective in January 2024.

The rates do not reflect the Purchased Gas Adjustment, which is passed through from gas and major pipeline suppliers and can fluctuate monthly based on the price of natural gas.

Rate schedules are subject to gross receipts taxes, city and state taxes and franchise fees, where applicable.

Base rates are part of the Customer Charge and Distribution Charge line items on your bill. The Distribution Charge is a grouping of several costs, including your base rate, a charge for energy conservation programs, legacy pipeline replacement and other costs.

$18.10 → $25.50
EXISTING PROPOSED

Raise by 41%

TECO PEOPLES GAS
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PeoplesGas.com/rates

PLEASE A 41% RAISE on Customer Chg. IT IS HARD

ATTACHMENT C


Mr Gilles C Fouquet
2131 Alameda Ave
Sarasota, FL 34234-8352

DISTRIBUTION CENTER
2023 JUN 22 AM 8:52

TAMPA FL 335
SAINT PETERSBURG FL
20 JUN 2023 PM 3 L

The PSC Docket # 20230023-GU
Office of the Commission Clerk
2540 SHUMARD OAK BLVD
Tallahassee FL 32399-0850

32399-085099

ATTACHMENT C

Donald "Mac" Spencer
2180 Sparrow Court
Sarasota, Florida 34239
Spencer53@comcast.net
941-955-7399 Home 941-321-8960 Cell

June 19, 2023

Office of the Commission Clerk
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

RE: Docket # 20230023-GU TECO

This increase of 32% on most items seems excessive and TECO's statements seem to be misleading. Three of Teco's misleading statements in the attached notice are below:

1. **"in the past 15 years we have raised rate only once"**

   But that omits the fact that the increase was in 2021 only two years ago AND that increase was a 32% increase WOW.

2. **"Florida population growth has been remarkable, resulting in more new home and commercial construction "**

   But that omits fact that TECO charges for all the new installations and it adds to their profitable customer base as their business expands.

3. **"People's Gas must invest in new – and upgraded existing – infrastructure to serve this demand as well as hire additional team members"**

   But again, that omits the fact that they will have many new customers who will be paying them for the service and the installations. Which, again, adds to their profitable customer base.

Sincerely,

Donald Spencer

Encl: TECO notice copy

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How the Proposed Changes in Rates and Charges May Impact Your Bill

The following tables show how the proposed rates and service charges compare with what you pay today.

Rate Class	Annual Therm Usage	Current Monthly Rates		Proposed Monthly Rates		
		Customer Charge	Base Rate	Customer Charge	Base Rate	Increase %
RS-1	0 - 99	$ 15.10	$ 0.27011	$ 19.95	$ 0.36738	**32%**
RS-2	100 - 249	$ 18.10	$ 0.27011	$ 25.50	$ 0.36738	**41%**
RS-3	250 - 1,999	$ 24.60	$ 0.27011	$ 32.95	$ 0.36738	**34%**
RS-GHP	N/A	$ 24.60	$ 0.09598	$ 32.95	$ 0.12950	**34%**
RSG (Residential Standby Generator)	< 19 therms	$ 23.91	$ 0.00000	$ 32.95	$ 0.29500	**38%**
	> 20 therms	$ 23.91	$ 0.27011	$ 32.95	$ 0.29500	**38%**

Miscellaneous Service Charges	Current	Proposed
Residential Meter Turn On	$63.00 ($29.00 per additional meter)	$78.00 ($34.00 per additional meter)
Residential Meter Reconnect	$87.00 ($28.00 per additional meter)	$104.00 ($33.00 per additional meter)
Account Opening	$24.00	$33.00
Temporary Turn-off Charge	$30.00 per meter	$33.00 per meter
Failed Trip Charge	$25.00	$25.00
Trip Charge/Premise Collection	$25.00	$29.00

If approved, the proposed rates and service charges would be effective in January 2024.

The rates do not reflect the Purchased Gas Adjustment, which is passed through from gas and major pipeline suppliers and can fluctuate monthly based on the price of natural gas.

Rate schedules are subject to gross receipts taxes, city and state taxes and franchise fees, where applicable.

Base rates are part of the Customer Charge and Distribution Charge line items on your bill. The Distribution Charge is a grouping of several costs, including your base rate, a charge for energy conservation programs, legacy pipeline replacement and other costs.

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Notice of Rate Request and Customer Service Hearings

On April 4, 2023, Peoples Gas System filed a request (Docket 20230023-GU) with the Florida Public Service Commission (PSC) requesting a future increase in base rates. If approved as filed, the increase will vary by customer rate class and would likely take effect in January 2024.

Florida's population growth has been remarkable, resulting in more new home and commercial construction, more businesses, stores and restaurants, new and expanded infrastructure including roadways, and more electricity generation fueled by natural gas.

While we have managed our business prudently, Peoples Gas must invest in new – and upgrade existing – infrastructure to serve this demand, as well as hire additional team members to operate and maintain the expanding system.

And, like other businesses, we have been impacted by higher-than-expected inflation, labor market challenges, supply chain disruptions and rising interest rates.

The decision to raise rates is not an easy one for us; in the past 15 years, we have raised rates only once. Since our last increase, we have: invested in and deployed critical technology to help us operate more efficiently; connected thousands of customers to ways to save energy and money through our free energy audit and conservation programs; invested in the safety of the public and our system; and continued to provide an award-wining customer experience.

We are committed to delivering reliable and environmentally responsible natural gas, while making safety and top-tier customer service our priorities.

Hearings

The PSC has scheduled the following in-person and virtual public hearings to provide customers an opportunity to express their views on quality of service and the impact of the requested rate increase:

In-Person Hearings:

Wednesday, June 28, 2023 at 2 p.m.
Charles F. Dodge Center
601 City Center Way Pembroke Pines, FL 33025

Thursday, June 29, 2023 at 2 p.m.
Hillsborough Community College – Brandon Campus
10451 Nancy Watkins Drive Tampa, FL 33619

Virtual Hearings:

Monday, July 10 at 10 a.m. and 2 p.m.
Tuesday, July 11 at 2 p.m. and 6 p.m.

If you would like to testify before the PSC by phone at one of the virtual customer service hearings, you must sign up by contacting the PSC by calling **1-850-413-7080** or emailing **speakersignup@psc.state.fl.us**.

Once you sign up, you will be provided further instructions on how to participate, including the call-in number. The order in which customers testify is based upon the order in which they sign up. If attending in person, please arrive early. For virtual hearings, please sign up as soon as possible, but at least two business days prior to the service hearing you plan to attend. If you have questions about the sign-up process, please call **1-850-413-7080**.

On Aug. 29 – Sept. 1, 2023, the PSC will conduct a technical hearing to allow Peoples Gas and other parties to the proceeding to present testimony and relevant evidence regarding the rate request.

To watch either the customer service hearings or the technical hearing live, visit **www.FloridaPSC.com** and click on the "Watch Live" link. If you do not have access to the internet, you may call **1-850-413-7999** to listen to the hearings. If you are hearing or speech impaired, you may contact the PSC by using the Florida Relay Service at **1-800-955-8771** (TDD).

Resources

An overview of the rate request and copies of the complete filing are available online at **www.FloridaPSC.com** and **www.PeoplesGas.com/rates**.

If you would like to share your comments with the PSC regarding the proposed changes in rates, please write to the PSC at the following address and reference Docket No. 20230023-GU:

Office of the Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

To submit comments regarding your utility service, please contact the PSC's Office of Consumer Assistance and Outreach by calling **1-800-342-3552**.

At any time during this process, you may contact the Office of Public Counsel (OPC). The OPC was established by the Florida Legislature to represent you and the other utility consumers before the PSC.

The Public Counsel is independent from the PSC and can be reached at **1-800-342-0222** or **www.FloridaOPC.gov**.

Please view the tables on the following page to understand how the proposed changes in rates and charges may impact your bill. Visit **www.PeoplesGas.com/rates** for more information.

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Darius Robinson

From: John Plescow
Sent: Friday, June 23, 2023 3:48 PM
To: Consumer Correspondence; Consina Griffin-Greaux
Subject: FW: Monthly Gas Bill

Correction, add to docket 20230023.

From: John Plescow
Sent: Friday, June 23, 2023 2:21 PM
To: Consumer Correspondence <ConsumerCorrespondence@PSC.STATE.FL.US>; Consina Griffin-Greaux <CGriffin@psc.state.fl.us>
Subject: FW: Monthly Gas Bill

Please, add to docket 20220069.

From: Consina Griffin-Greaux <CGriffin@psc.state.fl.us> **On Behalf Of** Consumer Contact
Sent: Friday, June 23, 2023 1:18 PM
To: John Plescow <JPlescow@PSC.STATE.FL.US>
Subject: RE: Monthly Gas Bill

John,

Please send to clerk's office. I am awaiting your response. Case# 1423804C, I will add the notes once I receive an email back from you.

Thanks

Consina

From: Scudder Graybeal <dsgraybealtn@aol.com>
Sent: Friday, June 23, 2023 10:38 AM
To: Consumer Contact <Contact@PSC.STATE.FL.US>
Subject: Monthly Gas Bill

Your proposed rate increase for 2024 is outrageous. In my case , rate class RS-2, that amounts to a 40% increase. Inflation is not quite that high! Unacceptable.

Scudder Graybeal
1310 Bando Lane
The Villages, FL 32162
dsgraybealtn@aol.com
630 965-8513

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CORRESPONDENCE
6/29/2023
DOCUMENT NO. 03871-2023

Antonia Hover

From:	Wessling, Mary <Wessling.Mary@leg.state.fl.us>
Sent:	Thursday, June 29, 2023 2:06 PM
To:	Records Clerk
Subject:	FW: Rate Increases from TECO Gas and Duke Energy

Please include the below comments in Docket No. 20230023-GU.

Thanks,

Mary "Ali" Wessling, Esq.
FL Bar # 93590
Office of Public Counsel
111 West Madison Street, Suite 812
Tallahassee, FL 32399-1400
Phone: (850) 717-0341
Fax: (850) 487-6419

From: Joe Chisar <jcchisar@yahoo.com>
Sent: Thursday, June 29, 2023 11:32 AM
To: Wessling, Mary <Wessling.Mary@leg.state.fl.us>
Subject: Rate Increases from TECO Gas and Duke Energy

Thursday June 29, 2023

Mary Wessling, (Allie) Lawyer, Florida Office of the Public Council

To: wessling.mary@leg.state.fl.us

Mary Allie, Thank YOU, your legal team and staff for helping to make life better for ALL Florida residents!

I would like to submit my opinion, thoughts for the Duke Energy proposed residential rate increase coming up in 2023. Please consider my letter when the Duke Energy proposed rate increase happens. I do not a have a docket number.

Here is a snap shot of what Commissioners have approved of every customer charge rate increase from Duke Energy in Florida:

January 2018 RS-1: $8.82 per kWh

January 2019 RS-1: $9.66 per kWh

January 2020 RS-1: $10.52 per kWh

April 2020 RS-1: $10.58 per kWh

September 2020 RS-1: $10.63 per kWh

January 2021 RS-1: $11.40 per kWh

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April 2021 RS-1: $11.52 per kWh

January 2022 RS-1: $12.45 per kWh

January 2023 RS-1: $12.51 per kWh

All residents of Florida need a customer service rate decrease.

Since January 2018 I have been emailing and asking Every Florida Commissioner, Florida House and Senate representatives in Tallahassee, Why, I can NOT purchase Natural Gas and Electric Power on the Open Market for my home? And every year there is **NOTHING** Done!

Why are All republican politicians refusing to help ALL Florida residents? Many other states have programs to purchase Electric power and Natural gas on the open market! It seems to me that the gerrymandered republican controlled congress are determined to make life as difficult as possible for every Florida resident to keep Duke Energy and TECO Gas monopoly intact. In the 2024 election cycle I will be voting for All and Every Democrat running for office in Florida!

How many TECO Gas and Duke Energy Lobbyist's and Staff bribed Florida Commissioners, House and Senators in Tallahassee to keep the TECO Gas and Duke Energy monopoly intact!

I am respectfully requesting that every commissioner rejects Duke Energy rate increases and proposals for the "RS-1" for 2 years including **ALL** Hidden Taxes / Fees.

My only income is my Social Security that I have cut my household budget to the bare bone my Social Security Cost of Living (COLA) has been decimated, absorbed and does not keep up with inflation because of the manufactured inflation by Boards of Directors, Chief Executive Officers (CEOs) and Wall Street Analysts Greed that are to blame for the current 9.5% inflation crisis by raising prices for **All** goods and services in every industry and pass their price gouging on me the public so they get financially wealthier to satisfy Wall Street Analysts Expectations Greed that have made Trillions of Dollars in profits over the last 50 years for the top 1%, while the bottom 99% got financially screwed!

I am a retired senior and have many serious medical health issues that require I have power to run my life saving medical health equipment at all times.

Joseph C. Chisar

8855 SE 136th Lane

Summerfield, FL. 34491

352-425-9977

jcchisar@yahoo.com

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CORRESPONDENCE
7/11/2023
DOCUMENT NO. 04009-2023

Ralph Leslie
13804 Swiftwater Way
Lakewood Ranch Fl 34211
301-312-7403

Florida Public Service Commission

Docket No. 20230023-GU

I am protesting the Peoples Gas System rate increase in this docket based on the excessive Purchased Gas cost that TECO charges myself and its other customers. The Florida PSC should not approve this rate increase until TECO reduces the purchased gas cost to a reasonable rate.

Currently the TECO purchased gas cost (that they supposedly do not make any money on) is 90 cents a therm. The current spot natural gas price is $2.70 a 1000 cubic feet. This about 27 cents per therm. The Florida Gas Transmission 100% load factor rate is 78 cents per dekatherm or 7.8 cents a therm. This is only 35 cents a therm. Adding some gathering costs and marketers profit would still put it around 45 cents a therm delivered to Peoples Gas. Yet we are being charged double that!! Peoples is making millions of dollars every day from the purchased gas charge. Until this rate is reduced, The Florida PSC should not approve the rate increase filed for in this docket.

Currently in Maryland, where customers can purchase gas independent of Washington Gas Light, marketers are offing 1 and 2 year contracts for around 45 cents a therm, even though the pipeline suppliers to Washington Gas Light (Transco and Columbia Gas) have higher transportation rates than Florida Gas Transmission.

I worked for the Federal Energy Regulatory Commission for 34 Years in Pipeline Rates and worked on and supervised over 200 Interstate Pipeline rate cases in my career. I retired to Florida 10 years ago.

Please investigate TECO's excessive purchased gas rate and reduce it to the proper charge. Thank You.

Ralph Leslie

Ralph Leslie

ATTACHMENT C

Office of the Commission Clerk
2540 Shumard Oak Blvd
Tallahassee, Fl.

Docket # 20230023-GU

Comments to share with the PSC regarding TECO proposed rate hikes.

Information received from TECO shows the following increases:

RS1 32.1%
RS2 40.8%
RS3, RS4, RS GHP, RSG, each 33.9%

Miscellaneous Service Charges:

Residential meter turn on 23.8%
Residential meter reconnect 19.5%
Account opening 37.5%
Temporary turn off 10%
Failed trip charge 0%
Trip charge/premise collection 16%

TECO states in opening of communication, reasoning for increases:
paraphrased -
population growth resulting in new home/commercial construction, businesses, etc....
Investing in new/upgraded infrastructure and personnel.

1. Well, welcome to real economics! Does not the increase in business generate additional revenues and profits? And does this not cover costs of supplying a service? To expect customers to pay for a company to add infrastructure and personnel to service an expanded customer base who then must pay monthly bills for the same service is somewhat absurd.
Most companies would be ecstatic about an expanded base, generating more revenue and profits; especially when the increase in accounts was provided by an outside (state of Florida providing an excellent environment, natural and governmental for people moving here at no cost to TECO) agency without any direct cost to the company for procuring them i.e., advertising etc....!
These needs are for essentially all private businesses, a cost of doing business, and one would be hard pressed to site a company for sending its customers a bill-think medical practices, automotive repair, retail stores, grocery stores and many others.

2. TECO does note impact from inflation, labor, supply chain, and interest rates, reasonable points.
All these are cyclical, going up at times, and down others; business cycles that all companies and individuals experience. Rarely, does one see a request for a rate DECREASE when these points lower......still, some coverage of these may be justified

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but not for what I see as exorbitant increases
-32.1% to 40.8% for Rate Class, and 10%-37.5% for Miscellaneous Service, excluding Failed Trip Charge which arguably should not change if even exist!

Please consider these comments in responding with only reasonable changes to the points noted in #2, and disregard increases requested in #1.

Sincerely,
A concerned Florida resident

TAMPA FL 335
SAINT PETERSBURG FL
21 JUN 2023 PM 3 L

Office of the Commission Clerk
2540 Shumard Oak Blvd.
Tallahassee, Fl 32399-0850

32399-701940

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