BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	:	DOCKET NO. 000824-EI Submitted for Filing: January 18, 2002

DIRECT TESTIMONY OF
SHEREE L. BROWN ON BEHALF OF
PUBLIX SUPER MARKETS, INC.

DIRECT TESTIMONY OF
SHEREE L. BROWN ON BEHALF OF
PUBLIX SUPER MARKETS, INC.

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Sheree L. Brown and I am a Managing Principal of SVBK Consulting Group, Inc., a subsidiary of Alliant Energy Integrated Services, located at 710 N. Orange Ave., Suite 710, Orlando, Florida 32801.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A: I graduated Magna Cum Laude from the University of West Florida with a B. A. in Accounting and later received a Masters in Business Administration degree from the University of Central Florida. I am a Certified Public Accountant in the State of Florida and am a member of the American Institute of Certified Public Accountants and the Florida Institute of Certified Public Accountants.

Since 1981, I have provided utility consulting services to regulators; municipal, cooperative, county and institutional utilities; and industrial consumers in matters pertaining to electric, water, wastewater, natural gas, steam heat and chilled water utilities. My work has focused in the areas of regulatory affairs, revenue requirements and cost of service, rates and rate design, deregulation and stranded costs, valuation and acquisition, feasibility studies and contract negotiations. A more detailed description of my experience is included in my resume that is attached hereto as Exhibit SLB-1.

Q: ON WHOSE BEHALF ARE YOU SPONSORING THIS TESTIMONY?

A: I am sponsoring this testimony on behalf of Publix Super Markets, Inc. ("Publix").

Q: WHAT ARE THE INTERESTS OF PUBLIX IN THIS PROCEEDING?

A: Publix is a Fortune 500 company employing 135,000 employees in 675 supermarkets, 8 distribution centers and 3 manufacturing facilities with 93 supermarkets and one distribution center in Florida Power Corporation's ("FPC's") service territory. The Company is growing at the rate of approximately 50 stores per year. The typical Publix store has a demand of 435 KW, with the range of monthly demands varying only from a low of approximately 403 KW to a high of approximately 479 KW. Due to refrigeration requirements, the supermarkets have an average load factor of 75% and Off-Peak usage is 72% of their total energy requirements. Electricity makes up a significant portion of Publix' operating expenses. As a major consumer of electricity from FPC, Publix is very interested in the outcome of this proceeding.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to address FPC's proposed revenue requirements for the 2002 Test Year. I will also address FPC's allocation of revenue requirements between rate classes.

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony addresses the proposal of FPC Witnesses Cicchetti and Myers to recover merger-related Transition Expenses and Transaction Costs and to split the net merger savings between the customers and FPC. I conclude that FPC has incorrectly allocated the Transaction Costs to FPC and that the Transaction Costs should be reallocated to recognize that a portion of the purchase price was directly attributable to the acquisition of Florida Progress' unregulated businesses. I question the reasonableness of FPC's severance packages paid to executives and the Company's request for the recovery of such costs through the amortization of Transition Expenes. I explain that the benefits of the merger extend beyond the estimated merger-related savings and will provide significant benefits to the shareholder. I conclude that the amortization period requested by Witness Cicchetti is not justified and propose to amortize the Transition Expenses over a 20 year period and the Transaction Costs over a 40 year period, with a return at 7.5%. Lastly, I provide for a portion of earnings in excess of the authorized rate of return to be applied to faster amortization of the Transition Expenses and Transaction Costs.

I also address FPC's projected revenue requirements for Customer Accounting and Distribution expenses and propose an adjustment to the Test Year revenue requirement associated with these expenses. I further recommend amortization of Transmission expenses that the Company has projected for the Test Year to increase system reliability through required repairs and upgrades. I address the Company's allocation of Power Marketing expenses and recommend that a portion of such expenses be absorbed by the shareholders to recognize the advantages of the Power Marketing function to FPC through the sharing of gains on sales approved by the Florida Public Service Commission ("FPSC" or the "Commission"). I further recommend that the remaining portion be allocated between the retail and wholesale jurisdictions.

Regarding the Company's requested amortization of Rate Case expenses, I am proposing that the Company's Rate Case expenses for 2001 should either be absorbed by the Company or applied to the Tiger Bay accelerated amortization, at the Commission's discretion. I am proposing to amortize the remaining balance over 4 years.

I am recommending that amortization of the Last Core Nuclear Fuel and the end-of-life nuclear materials and supplies be extended to 35 years to recognize the probability that FPC will obtain a license extension on the Crystal River 3 ("CR3") unit. Lastly, I am proposing to reduce the accruals to the Storm Damage fund and, at a minimum, to recognize lower Test Year expenses in the development of the rate base offset for the fund balance.

MERGER ADJUSTMENT

Q: HAVE YOU REVIEWED THE TESTIMONY OF FPC WITNESSES CICCHETTI AND MYERS?

A: Yes.

Q: PLEASE EXPLAIN THE MERGER ADJUSTMENT PROPOSED BY WITNESSES CICCHETTI AND MYERS.

A: FPC Witnesses Cicchetti and Myers are proposing to increase the Test Year revenue requirements by $58.7 million to remove FPC's estimated merger-related savings which FPC claims were incorporated into the Test Year operating budget. They then propose to give the retail customers an annual credit of $5 million, reflecting approximately one-half of the net savings they have calculated by offsetting the estimated merger-related savings by amortization of Transition Expenses and Transaction Costs. This adjustment is explained as follows:

1) Progress Energy is estimating total merger-related savings of $175 million a year, with $58.7 million of those savings anticipated for FPC.
2) Since a large portion of the estimated savings is due to reductions in FPC's labor force, FPC is proposing to amortize $69.676 million in severance costs which were incurred in the labor force reduction as "Transition Expenses". These severance costs are being

amortized over a 15 year period. Since the severance costs were tax-deductible to FPC, the revenue impact of this amortization is a cost of $4.645 million per year for FPC's customers. These costs are allocated 94.45% to the retail jurisdiction, costing FPC's retail customers $4.387 million a year.

3) Progress Energy paid approximately $924.038 million in excess of the pre-merger market value for the purchase of Florida Progress' equity. Witness Cicchetti refers to this premium as the "Transaction Cost". Of this total Transaction Cost, Witness Cicchetti has allocated $269.824 million to FPC's retail customers. He is proposing to amortize this amount over a 15 year period at an after tax interest rate of 4.607%, resulting in an annual amortization of $25.310 million before the tax gross-up. Since the Transaction Costs are not tax-deductible to Progress Energy, the revenue impact of this recovery is actually $41.204 million per year to FPC's retail customers.

4) The total Transition Expenses and Transaction Costs that FPC is proposing to recover from the retail customers is thus $45.592 million a year.

5) The retail share of the estimated merger-related savings is $55.441 million; therefore, the "net" merger-related savings would be approximately $9.85 million dollars.[1]

6) Witnesses Cicchetti and Myers are proposing to give the FPC retail customers a credit of only $5 million a year, representing approximately one-half of the estimated "net" merger-related savings.

Q: IS FPC PROPOSING TO INCLUDE THE ACQUISITION ADJUSTMENT IN RATE BASE?

A: No. Witness Cicchetti stated that:

> Importantly, FPC is not proposing an acquisition adjustment be included in rate base... (Cicchetti, page 21)

He further states that :

> The FPSC has allowed acquisition adjustments to be put in rate base in "extraordinary" circumstances. This actually increases rate base by the amount of the adjustment and raises the rates paid by the customer. Again, this is not what FPC is proposing here. (Cicchetti, page 23)

Although FPC is not proposing to include the Transaction Costs in rate base, his proposal is very similar to including the Transaction Costs in rate base and ***does*** increase the rates paid by the customer. Dr. Cicchetti is proposing to earn a return on the unamortized balance of the Transaction Costs by amortizing the Transaction Costs at an effective rate of 7.5%, based on the cost of Progress Energy's merger-related debt. As explained earlier, the $25.310 million in annual amortization proposed by Dr. Cicchetti must be grossed-up for taxes,

1 This level of savings differs from the amount shown in Witness Cicchetti's testimony, Table 1, due to a difference in the tax gross-up factor. Although Witness Cicchetti used a tax rate of 38.575% used in calculating the after-tax savings, he used a tax rate of 38.699% in calculating the net pre-tax synergies. The $9.85 million net savings were calculated using the tax rate of 38.575%.

resulting in an annual revenue requirement of $41.204 million.

The main difference between Dr. Cicchetti's method and the rate base approach is that Dr. Cicchetti's approach provides a levelized revenue requirement, while the rate base approach results in declining revenue requirements over time. Dr. Cicchetti's comments should not be taken to imply that FPC is not asking for a return on the Transaction costs.

Q: DO YOU HAVE ANY CONCERNS WITH THE MERGER ADJUSTMENT PROPOSED BY WITNESSES CICCHETTI AND MYERS?

A: Yes. I have several concerns with the merger adjustment proposed by Witnesses Cicchetti and Myers.

1) Witnesses Cicchetti and Myers argue that it is necessary to allow recovery of the Transaction Costs and Transition Expenses to encourage mergers that provide net benefits for customers. If such recovery were required to encourage the merger, it would be reasonable to think that Progress Energy would have petitioned the Commission prior to the merger to assure that such recovery would be allowed. Carolina Power & Light Company ("CP&L") obviously anticipated merger benefits that would accrue to shareholders.

2) In his deposition, Witness Cicchetti indicated that the $175 million of estimated merger-related savings was attributable to savings between CP&L and FPC. Dr. Cicchetti then allocated the Transition Expenses and Transaction Costs between CP&L and FPC based on the relative merger-related savings. This methodology does not recognize the value paid by CP&L for acquisition of the unregulated subsidiaries.

3) Witness Myers claims that merger savings are estimated to be $58.7 million, therefore,

FPC has designed a method of recovering the Transition Expenses and Transaction Costs that will result in net savings of $9.85 million to "share" between the retail customers and FPC. While FPC has indicated that numerous actions have been taken to result in the estimated $58.7 million in savings, isolating the true merger-related savings from savings that could have been achievable even without the merger is an inaccurate exercise. Based on the changes in FPC's operating and maintenance costs since the merger, the claimed merger savings have been more than offset by increases in other costs. This raises a question of whether the merger has really resulted in substantial savings that justify the requested amortization of the Transition Expenses and Transaction Costs.

4) FPC's Transition Expenses include high payouts to executives that do not appear to be reasonable for inclusion in the retail customers' revenue requirements.

Q: WHAT OTHER BENEFITS WERE ANTICIPATED BY CP&L IN ITS ACQUISITION OF FLORIDA PROGRESS?

A: CP&L's reasons for the acquisition were set forth in Florida Progress' Notice of Annual Meeting of Shareholders, July 5, 2000, at pages 48 through 50. A review of those reasons shows that a primary driving factor for the acquisition was to increase CP&L's competitive position in anticipation of deregulation. Among the reasons provided were:

(i) The combined company is expected to be capable of offering energy and a broad variety of low-cost, quality energy-related services to a broader customer base during a time of rapid change in the utility industry. (Page 48)

(ii) Florida Progress' substantial generation capacity, strategically located in

Florida adjacent to the attractive Georgia market, should complement Carolina Power & Light's generating assets, located in North Carolina and South Carolina, and should provide the combined company with greater access to these competitive markets. (Page 48)

The combined company's greater generation assets and customer base should provide the combined company with the size and scope to compete in the increasing competitive utility markets. (Page 49)

(iv) Greater scale should result in significant cost efficiencies and lower per unit costs, resulting in the improvement of the utility businesses' competitive position in a deregulating and increasingly competitive industry with resulting benefits to utility customers. (Page 49)

(v) The resulting lower cost structure for CP&L Energy's regulated businesses should reduce potential customer and margin loss that could occur due to the effects of deregulation. (Page 49)

In a Finance Committee presentation to CP&L given on August 4, 1999, page 7, "Wall Street Highlights" listed several anticipated benefits, including the strengthening of the competitive position of the expanding generation asset base and the expansion of business diversification. These reports, along with several analysts' reports also indicated that the merger was anticipated to be accretive in the first full year after closing.

In a merger announcement which was published on August 23, 1999, Mr. William Cavanaugh, Chairman, President and Chief Executive Officer of CP&L recognized that the acquisition would enhance CP&L's competitive position. The press release further recognized that the combined companies' non-utility businesses were a strong supplement to utility earnings growth and that non-utility revenues will represent approximately 15% of the revenues of the combined company.

In CP&L's August 20, 1999 Minutes of Meeting of Board of Directors, it was noted that Mr. Cavanaugh said:

> the proposed acquisition would give us a potential to grow earnings more rapidly, provide substantial generation capacity strategically located on each end of the lucrative Georgia and South Carolina markets, and gives us the size necessary to thrive in a deregulated industry.

In the CP&L Board of Directors Strategic Planning Retreat 1999 Background Materials, page 6, CPL indicated that its acquisition of Florida Progress was the next logical step toward achieving a sustainable competitive advantage. It further noted that plans were in place to reduce every aspect of the cost of operations to be at or below market.

Q: HAS THE COMPANY PROVIDED ANY INFORMATION REGARDING ITS INTENTIONS TO EXPAND ITS COMPETITIVE GENERATION BUSINESS?

A: In a review of the Power Operations, Power Trading and Term Marketing functions, the Company provided several key considerations as the basis for revenue enhancements. These key consideration included increased experience in adjoining market regions, portfolio management practices, use of the automated information management system, and development of an improved risk management program. It was noted that the use of the FPC's portfolio management practices would "identify more uncommitted generation for sale, reduce production cost uncertainty and maximize the use of 'below market' assets. (OPC 010178). Lastly, the Company noted that:

> Combined, CP&L and FPC Trading Centers will generate revenue in

> excess of $250 million in 1999 producing an expected total margin of $60 million. ($40 million benefit to shareholders and $20 million to ratepayers). An increase in performance of at least 5% is anticipated due to the above considerations, thereby resulting in a minimum increase of $2 million in shareholder value and $1 million in retail customer value. (OPC 010178)

The report also noted that the firm transmission path from FPC to CP&L could be used to move power between regions for profit, when it is not being used to deliver power from FPC to CP&L. The benefits of this utilization were estimated at $2 million; however, the Company did note that the ownership of the transmission could require that these benefits go to customers. Attachment 4 of the report discusses the basis for revenue synergy from retaining existing business and penetrating other markets. This attachment indicated that wholesale term business was being "exited" at the fastest contractual rate and that it was assumed that approximately one-half, or 320 MW, would be retained, apparently under market-based, unregulated contracts. Further, the Company assumed an additional 320 MW from additional expansion opportunities in Florida. It was noted that the "Generation Expansion Team has the pro-forma and all financial documents to support the 5.0 million dollar revenue enhancement. (OPC 010181)

Q: WHAT ARE THE IMPLICATIONS OF THE COMPANY'S GOALS TO ENHANCE ITS COMPETITIVE POSITION AND PARTICIPATE MORE ACTIVELY IN THE GENERATION MARKET?

A: While cost savings were a major driving factor for the merger, these cost savings goals are not just to provide benefits to the customers. The cost savings are also intended to place CP&L and FPC in the best competitive position to capture a larger market share when deregulation occurs. In addition, the Companies expect to become a major "player" in the

Southeast generation market, which is already deregulated at the wholesale level. These benefits are expected to increase shareholder value. The implications of the Company's goal to enhance its competitive position and to participate more actively in the generation market are that the method of recovering Transition Expenses and Transaction Costs should recognize that there are many merger benefits to be enjoyed by the shareholders, as well as those benefits that will accrue to the customers. While all of these benefits have not been quantified, it is apparent that the Company is positioning itself to maximize its earnings in the competitive utility market and will reap the benefits of their strengthened competitive position for many years to come. These benefits should be considered by the Commission when determining the appropriate regulatory treatment of FPC's Transition Expenses and Transaction Costs.

Q: YOU MENTIONED EARLIER THAT FPC'S TRANSITION EXPENSES INCLUDE EXECUTIVE SEVERANCE PAYMENTS THAT DO NOT APPEAR TO BE REASONABLE FOR INCLUSION IN THE RETAIL CUSTOMERS' REVENUE REQUIREMENTS. PLEASE EXPLAIN WHY THESE PAYMENTS DO NOT APPEAR REASONABLE.

A: FPC's Transition Expenses include approximately $25 million in severance benefits paid to FPC executives, including the President and Chief Executive Officer ("CEO"), the Vice President and General Counsel, and the Vice President of Human Resources. The Company's 1999 Federal Energy Regulatory Commission ("FERC") Form 1 provides the salaries of the executives for 1999, including amounts earned under the management incentive compensation plan. These payments are set forth in Table 1 below, along with the severance packages provided to each, and the multiple of the executives' annual compensation that was paid out in severance.

TABLE 1 SUMMARY OF FPC EXECUTIVE COMPENSATION AND SEVERANCE PACKAGES			
Title	1999 Compensation	Severance Package	Multiple of Compensation Paid in Severance
President/CEO	$835,320	$8,099,799	9.7
VP and General Counsel	$366,557	$1,691,176	4.6
VP, Human Resources	$304,721	$1,495,931	4.9

As shown in Table 1, the severance packages provided in the Transition Expenses ranged from approximately 5 times to almost 10 times the executive's annual compensation. In addition to these three positions, FPC also paid an additional $13,760,863 to 11 executives, which is an average of $1.25 million per executive.

These payouts do not appear reasonable for the retail customers to absorb. The Commission should review the reasonableness of these expenses prior to establishing the appropriate regulatory treatment of FPC's Transition Expenses.

Q: HOW DID WITNESS CICCHETTI ALLOCATE THE TRANSITION EXPENSES AND TRANSACTION COSTS TO FPC?

A: Witness Cicchetti allocated the Transition Expenses and Transaction Costs to FPC based on the relationship between the estimated merger savings of $58.7 for FPC and the total estimated merger savings of $175 million.

Q: DID THE TOTAL SAVINGS INCLUDE ANY SAVINGS THAT WOULD ACCRUE TO THE SHAREHOLDERS?

A: Yes. The total merger-related savings included approximately $31.5 million in merger-related generation revenue synergies which would accrue to the shareholders. The allocation of the Transition Expenses and Transaction Costs would thus recognize this level of merger-related synergies attributed to the shareholders. Unfortunately, however, the allocation does not recognize that the generation revenue synergies are supported by the production function and that additional Transition Expenses and Transaction Costs should be allocated to the shareholders to recognize this support. Further, since the production function is supported by the Shared Services, the allocation of Transition Expenses and Transaction Costs should again recognize that the shareholders benefit from the costs which are borne by the FPC and CP&L retail customers.

Q: DO YOU HAVE SUFFICIENT INFORMATION TO ISOLATE THE COSTS THAT SUPPORT THE COMPANY'S EFFORTS TO INCREASE ITS PRESENCE AND PROFITABILITY IN THE WHOLESALE GENERATION MARKET?

A: No. However, the Commission should recognize that this support is provided in making its determination on the appropriate treatment of the Transition Expenses and Transaction Costs.

Q: DID THE TOTAL SAVINGS INCLUDE ANY SAVINGS ATTRIBUTABLE TO THE NON-REGULATED BUSINESSES?

A: Apparently not. In response to several data requests, the Company provided a detailed breakdown of the merger-related synergies. The total synergies shown on OPC 009781 were $147 million. Several other versions of this document were developed, showing different levels of merger-related synergies; however, to date, we have not seen a corresponding breakdown of the $175 million. The breakdown of the merger-related synergies does include revenue synergies related to generation, but does not include any savings attributable to Florida Progress' non-regulated businesses, including Electric Fuels or Progress Telecomm.

Q: WHAT WERE THE CORRESPONDING MARKET VALUES PLACED ON FPC AND THE UNREGULATED BUSINESSES?

A: Salomon Smith Barney developed an analysis of the market value of Florida Progress based on the "sum of the parts". This analysis was described on page 55 of the Florida Progress Notice of Annual Meeting of Shareholders on July 5, 2000. (OPC 3 008660 through 008826) Several scenarios were run by Salomon Smith Barney, resulting in several implied equity values for Florida Progress; however, in each of the scenarios, the implied equity value of the non-regulated businesses, excluding synthetic fuels, was $8.50 to $12.00 per share. The implied per share value of the synthetic fuels business was estimated to be $3.50 to $4.00. Assuming that the value paid for the non-regulated businesses was based on the mid-point of the values estimated by Salomon Smith Barney, the breakdown of the purchase price would be as shown in Table 2 below:

TABLE 2
BREAKDOWN OF THE PURCHASE PRICE BASED ON THE SALOMON SMITH BARNEY "SUM OF THE PARTS" ANALYSES

Value of the Non-Regulated Businesses	$10.25	18.98%
Value of the Synthetic Fuels Cash Flow	$ 3.75	6.94%
Remaining Value Assigned to FPC	$40.00	74.07%
Total Purchase Price per Share	$54.00	100.00%

Q: SHOULD ANY PORTION OF THE TRANSITION EXPENSES AND TRANSACTION COSTS BE ALLOCATED TO THE NON-REGULATED BUSINESSES?

A: Yes. It is obvious that a portion of the purchase price applied to the non-regulated businesses. As explained earlier, the achievement of cost savings is not the only benefit derived by the merger. There is value in these subsidiaries that will accrue to the shareholders and should be recognized in the allocation of merger-related costs. In the

Merrill Lynch analyses provided in OPC3 007376, Merrill Lynch showed compound average growth rates from 1999 to 2001 in the diversified coal, barge, and rail businesses of 7.6%, 10.9%, and 25.6%, respectively. The Transaction Costs should be allocated between the regulated and non-regulated businesses based on the acquisition price. The regulated portion of the costs should then be allocated to FPC based on the anticipated merger-related savings.

Q: WHAT ARE THE SAVINGS THAT FPC HAS ESTIMATED AND ATTRIBUTED TO THE MERGER?

A: Witness Myers indicates that FPC will realize $58.7 million in savings, resulting from the reductions in payroll and benefit costs by consolidating functions and programs with CP&L and displacing approximately 675 FPC employees, or about 13% of the FPC workforce. The breakdown of the estimated savings was provided on page 15 of Witness Myers' testimony and is as shown in Table 3 below (dollars in millions):

TABLE 3
BREAKDOWN OF ESTIMATED MERGER SAVINGS

Shared Corporate/Administrative Services	$24.8
Power Operations	$15.8
Transmission and Distribution	$ 7.1
Customer Service	$ 5.9
Nuclear Operations	$ 4.1
Energy Ventures	$ 1.0
Total	$58.7

In response to Citizen's Second Set of Interrogatories, Question 40(a), FPC provided a breakdown of the employee reductions by functions. The reductions were calculated as of August, 2001 and included 227 employees in Energy Delivery, which included customer service, 153 employees in Energy Supply, and 313 employees in Corporate Services. These reductions were offset by an increase of 18 temporary employees, which were not functionalized.

Q: HAVE THESE SAVINGS BEEN REFLECTED IN THE TEST YEAR OPERATING AND MAINTENANCE EXPENSES?

A: The level of merger-related savings actually included as offsets to the Test Year operating and maintenance expenses is not clear. Witness Myers explained that the estimate of annual synergies ranged from $100 million to $175 million and that Progress Energy made the high end of the range its objective in its 2002 annual budgeting process. Of the total merger-related synergies of $175 million, FPC claims that $58.7 million will be realized by FPC; however, these savings are not shown separately in the development of FPC's Test Year budget, which was provided in response to OPC's Interrogatory No. 82.

Q: DID FPC'S ESTIMATED TEST YEAR EXPENSES ACTUALLY DECLINE FROM HISTORICAL LEVELS DUE TO THE ESTIMATED MERGER-RELATED SAVINGS?

A: No. Although the estimated merger-related savings are equal to 12.8% of the Company's non-fuel operating and maintenance expenses in 2000, the Company is still projecting overall increases in operating and maintenance costs. If the estimated merger-related savings are fully reflected in FPC's Test Year operating and maintenance expenses, such savings are not sufficient to offset the cost increases that FPC has included in the Test Year. The costs of particular operating and maintenance expenses are rising dramatically, as I will demonstrate later in my testimony.

Q: COULD ANY OF THE ESTIMATED SAVINGS BE ACCOMPLISHED ON A STAND-ALONE BASIS?

A: Apparently so. Document OPC3 00766 is a handout from the Board 2000 Strategic Planning

Seminar addressing "Implications if Merger Falls Through". In that document, the Company noted that the delivery system would continue with implementation of the technology plan and with formation of a regional structure. It also listed continuation of its plan to close down retail stores; to transfer customer service, credit and billing and call centers to Energy Distribution; and to eliminate the retail sales effort.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH FPC'S ESTIMATED MERGER-RELATED SAVINGS?

A: Yes. A review of FPC's itemized breakdown of estimated merger-related expenses shows a cost of $568,119 for the projected impact of moving FPC's employees to common health and welfare plans and $822,948 for the projected impact of charging FPC's employees similar medical rates to those charged to CP&L employees. In response to Citizens Interrogatories 82 through 84, the Company listed several benefits that were expanded to match CP&L benefits. These benefits are set forth in Table 4 below:

TABLE 4 INCREASES DUE TO NEW BENEFITS	
Benefit	Increase from 2000 to 2002 ($ Millions)
Account 92640-Dental Program	$1.1
Account 92640-New Subsidized Programs	$ .6
Account 92641-Integration with Progress Energy	$1.4
Account 92641-Subsidized Vision and Dental	$ .5
Account 92670-Progress Energy Restricted Stock Grant Amortization	$ .9
Account 92670-Financial Planning Education	$ .1
Account 92670 – Change of Control Cash Payments	$.1
Total Due to New Programs	$4.7

Based on this information, it appears as if the merger-related savings are overstated and have not reflected all of the additional costs incurred as a result of the merger.

In addition, in his deposition on January 17, 2002, Witness Sipes indicated that the Company would either be hiring additional employees or contract employees to implement its reliability initiatives. Thus, while the Company incurred significant severance costs, which it is asking the customers to bear, and has estimated merger-related savings due to reductions in staffing, it appears that those reductions may not be sustainable and that Test Year costs have actually been increased to rehire staff or hire contractors.

Q: PLEASE HIGHLIGHT SOME OF YOUR ADDITIONAL CONCERNS OVER THE MERGER-RELATED BENEFITS CLAIMED BY FPC.

A: One area of concern is the high level of increases shown in Administrative and General expenses from 2000 to the Test Year. Witness Myers indicates that FPC will realize $24.8 million in merger-related savings due to shared corporate and administrative services. A review of FPC's historical administrative costs as compared to the post-merger charges from

Progress Energy Services raises questions as to whether these claimed merger-related savings are simply "masking" other large increases that FPC is proposing to collect from its customers. FPC's 2000 FERC Form 1 provides a breakdown of the Administrative and General expenses for 2000 and 1999. In order to provide a comparison of FPC's recurring Administrative and General expenses, Table 5 below shows the total Administrative and General expenses for 2000 and 1999, exclusive of Employee Pensions and Benefits and the non-recurring merger-related severance payments incurred in 2000. Employee Pensions and Benefits have been removed due to the large impact of the Pension Credit and the high inflationary factors for medical benefits.

TABLE 5
COMPARISON OF ADMINISTRATIVE AND GENERAL EXPENSES

	1999	2000
Total A&G Expenses	60,691,398	126,318,087
Less Pension & Benefits	(33,001,212)	(47,567,198)
Less Severance Costs		99,800,000
A & G Expenses, excl Pension & Benefits and Severance	93,692,610	74,085,285

Schedule C-21, page 6 of 8, sets forth the Test Year 2002 Administrative and General Expenses of $46,453,000. Removal of the pension credit increases this amount to $95,474,000. In addition, FPC changed its method of accounting for certain costs after the merger, resulting in a reclassification of $15,678,000 in additional Administrative and General expenses to other FERC accounts. To put 2002 expenses on a comparable basis to 2000 and 1999, these expenses are added back to the Administrative and General expenses, resulting in a total 2002 Test Year expense of $111,152,000. This level of Administrative and General Expenses is an increase of over $37 million from 2000 to 2002, representing an average increase of 22.49% per year. This would indicate that the level of increase for recurring expenses is even greater than 22.49%. If this level of expense is "net" of FPC's claimed savings of $24.8 million, then FPC's costs before the merger savings would be rising at a rate of 35.5% per year from 2000 to 2002. Thus, FPC's claim of $24.8 million in savings due to shared corporate services is rather "lost" in the much larger increases that FPC is asking the customers to absorb.

In addition to the increases demonstrated above for 2000 to 2002, the Company has also increased its benefit packages due to implementation of new programs to "match" the benefits provided by Progress Energy. As shown in Table 2 above, these new programs have resulted in increases of $4.7 million in the Test Year, while only $1.4 million was reflected in the merger savings estimates.

Q: HOW DO THE TEST YEAR EXPENSES COMPARE TO THE 1999 ACTUAL EXPENSES?

When compared to 1999 expense levels, the average growth in Administrative and General expenses is 5.86% per year after merger-related savings and 13.2% assuming that merger-savings were not realized. This comparison, however, does not recognize several reductions in Administrative and General expenses that were achieved in 2000, including $10.7 million in Outside Services, $4 million in Property Insurance, $4.4 million in Administrative and General salaries and $2.9 million in General Advertising expenses. The Company also expensed $7.3 million for Y2K issues in 1999.

Q: SHOULD THE COMMISSION ACCEPT WITNESS CICCHETTI'S AND WITNESS MYERS' RECOMMENDED MERGER ADJUSTMENT?

A: No. Witness Cicchetti's and Witness Myers' recommended merger adjustment is overstated and does not balance the interests of the shareholders and the customers. As explained above:

1) FPC's estimated merger-related synergies appear overstated due to costs incurred as a result of the merger and offsetting increases in Test Year operating and maintenance expenses.

2) FPC's allocation of the Transition Expenses and Transaction Costs does not recognize the value of the unregulated businesses.

3) FPC's estimated merger-related synergies do not reflect the costs incurred by the retail customers which allow the Company to achieve merger-related revenue synergies for the shareholders.

4) FPC's recommended amortization of the Transition Expenses and Transaction Costs does not recognize the total benefits that the Company anticipates in enhancing its ability to be a player in the competitive energy market.

5) The Transition Expenses include executive severance payments that appear unreasonable and should be reviewed by the Commission.

6) Further, if the customers are required to pay for the Transition Expenses and Transaction Costs incurred to achieve merger-related savings, then those savings should accrue to the customers. FPC's recommended "sharing" of the net savings is unnecessary to encourage the merger (or any prospective mergers).

7) As I will demonstrate further, many of FPC's estimated Test Year operating and maintenance expenses are excessive. Some of these large increases in operating and maintenance costs are attributable to "catch up" programs to repair and upgrade the transmission and distribution systems, while other large increases are unexplained. The Company's proposed increases in operating and maintenance expenses more than offset the claimed merger-related benefits.

In addition, it should be noted that, due to tax implications, the retail customers must pay $1.63 for every $1.00 of Transaction Costs incurred by the Company. These factors should be considered by the Commission in establishing a fair and equitable regulatory treatment for FPC's Transition Expenses and Transaction Costs.

Q: DO YOU HAVE A RECOMMENDED APPROACH FOR THE COMMISSION TO CONSIDER?

A: Yes. First, the Transaction Costs should be allocated between the regulated companies and the non-regulated businesses based on a reasonable assessment of the fair value of the companies and the price paid for the acquisition. The Transition Expenses and Transaction Costs allocated to the regulated companies should be further allocated to FPC based on the estimated merger synergies of FPC as compared to the total estimated merger synergies. The reasonable FPC-related Transition Expenses should be amortized over a 20-year period with no return on the unamortized balance. The Transaction Costs should be amortized over a 40 year period at the net of tax interest rate of 4.607% and grossed-up to allow FPC to pay taxes on the revenue received. In addition, Publix Witness Kury has established an earnings sharing provision. To the extent that FPC's earnings are in excess of the authorized rate of return, the excess will be shared as set forth in Witness Kury's testimony, with FPC's share going to accelerate amortization of the Transition Expenses and Transaction Costs on a prorata basis.

Q: IN THE EVENT OF DEREGULATION, SHOULD THE UNAMORTIZED BALANCE OF TRANSITION EXPENSES AND TRANSACTION COSTS BE TREATED AS A STRANDED COST?

A: Although the final treatment of the Transition Expenses and Transaction Costs would be decided in the context of deregulation proceedings, the recovery of the Transition Expenses and Transaction Costs should not be a "given" when determining any stranded cost charges that may be applicable in the event of deregulation. As mentioned earlier in my testimony, the merger has allowed the Company to position itself to be a stronger competitor in a deregulated market. If, then, the retail market is deregulated, the Company should bear a much greater share of the Transition Expenses and Transaction Costs incurred. Further, the Commission should bear in mind that the recovery of the Transaction Costs is similar to allowing the Company to recover costs for acquiring FPC at a price greatly exceeding the book value of FPC, which is similar to a "stranded benefit". To allow this recovery and to then also claim that the market value of the Company's assets is below book value, and that a portion of the costs of such assets are then "stranded" is a double-whammy for FPC's customers which should be taken into consideration in either the Commission's decision in this proceeding regarding the recovery of Transaction Costs or in any future deregulation proceeding.

Q: HAVE YOU CALCULATED THE IMPACT OF YOUR RECOMMENDED ADJUSTMENT?

A: Yes. As explained earlier, FPC incurred $69.676 million in severance costs and executive payouts. While the executive payouts do not appear reasonable, I have calculated amortization of the total $69.676 million over a 20 year period. This amortization would result in an annual revenue requirement of $3,483,800 for the total system. As explained earlier, if the Commission finds any portion of the severance costs to be unreasonable for recovery by the retail customers, the amortization would be reduced accordingly. As shown in Table 1 above, the total purchase price would be allocated 70% to the regulated companies and 30% to non-regulated businesses. Applying 30% of the total Transaction Costs of $924.038 million to the unregulated businesses would leave $646.827 million to be allocated between the regulated companies. Of this amount, 30.9%, or $199.869 million would be allocated to FPC, based on the relative estimated merger-related savings.

Applying the retail jurisdictional allocation factor of 94.45% to the Transition Expenses and Transaction Costs results in total jurisdictional Transition Expenses of $3.29 million and total jurisdictional Transaction Costs of $188.776 million. Amortization of the Transaction Costs over a 40 year period at the after tax interest rate of 4.607% would result in annual amortization of $10.416 million, which must then be grossed-up for taxes, resulting in a revenue requirement of $16.957 million for the retail customers. The combined revenue requirement associated with the amortization of the Transition Expenses and the Transaction Costs would be $20.247 million. The impact of this adjustment is a reduction of $35.194 million to the retail cost of service (elimination of the Company's proposed $55.441 million in merger adjustment to the retail jurisdiction less the $20.247 million revenue requirement associated with the amortization). Offsetting this reduction by the $5 million credit proposed by Witness Cicchetti provides a net retail revenue impact of $30.194 million.

Q: DO YOU HAVE ANY CONCERNS WITH FPC'S FORECASTED TEST YEAR OPERATING AND MAINTENANCE EXPENSES?

A: Yes. Aside from the significant growth in Administrative Expenses explained above, I have several concerns with the level of certain other operating and maintenance expenses forecasted by FPC for the Test Year. I have concerns with the Company's projection of Distribution operating and maintenance expenses, the storm damage accrual and reserve levels, the allocation of Power Marketing expenses, the Last Core Nuclear Fuel, the End-of-Life Nuclear Materials and Supplies, Transmission operating and maintenance expenses, the Tiger Bay accelerated amortization, and the amortization of rate case expenses. My concerns are addressed below.

DISTRIBUTION OPERATING AND MAINTENANCE EXPENSES

Q: PLEASE DESCRIBE YOUR CONCERNS WITH THE LEVEL OF TEST YEAR DISTRIBUTION OPERATING AND MAINTENANCE EXPENSES ESTIMATED BY FPC.

A: The Company is projecting an increase of $19.9 million (26%) in distribution operating and maintenance expenses from 2000 to 2002. A portion of this increase is due to the Company's accounting change in the allocation of benefits; therefore, if the benefits loading adjustment of approximately $1.956 million is removed from the calculation, the Distribution expenses increased 23%. This increase is ***net of*** estimated merger syngeries of $5.5 million;

therefore, the projected increase without the estimated merger synergies would be $25.4 million, or 33% (30% excluding the benefits loading change). FPC Witness Sipes provides details of the Company's proposed distribution reliability initiatives, which are to be implemented in the 2002 to 2004 time frame at a total capital cost of $126.807 million and total operating and maintenance costs of $20.1 million. These distribution reliability initiatives contributed $7 million of the increase in distribution operating and maintenance expenses for the Test Year.

Exhibit SLB-2 provides a historical breakdown of the Company's distribution expenses from 1996 through 2000 from the Company's FERC Form 1's as compared to the Test Year projection. As shown on Exhibit SLB-2, FPC's total distribution costs rose from $66.2 million in 1998 to $76.6 million in 1999, then stayed relatively constant for 2000 at $77.2 million. Exhibit C-12 shows 2001 projected expenses of $74.7 million, even with the benefits loading change which occurred in 2001.

As explained in Witness Sipes' testimony, the Company implemented another three year distribution improvement program in 1999, which they called the "D2K" program. This program included substantial improvements, which were described by Witness Sipes on pages 6 through 8 of his testimony. The large increase of $10.4 million in Distribution operating and maintenance expenses from 1998 to 1999 should be partially explained by the implementation of the D2K program. Since this was a three year program, it is reasonable to assume that the extraordinary expenses associated with D2K would be eliminated in 2002—then "replaced" by the new three-year program to increase system reliability. In fact, Schedule C-65, page 7, shows $3.8 million in consulting services alone which were specifically identified as D2K related. Further, in his deposition on January 17, 2002, Mr. Sipes indicated that FPC had spent approximately $10 million on tree-trimming in 1999 and $9 million in 2000. Schedule C-12 shows $11.1 million in 1999 and $9.8 million in 2000. Although FPC's costs for tree-trimming were between $9 and $11 million in 1999 and 2000, the Company has treated its reliability initiative of $1.6 million in vegetation management as an incremental cost for 2002. Mr. Sipes also indicated that FPC would be hiring additional employees or contract employees to implement the reliability initiatives; therefore, the merger-related savings attributable to reductions in labor will be offset by increased staffing in the Test Year.

Exhibit SLB-2 calculates the increase in Distribution operating and maintenance expenses from 1998 to 1999 that would be expected based on application of general inflation and customer growth rates. As shown on Exhibit SLB-2, the 1999 expenses attributable to general inflation and customer growth would be $69.17 million. The remainder of the actual increase from 1998 to 1999 was $7.473 million, which I assumed was attributable to the D2K program. Escalating this amount to 2002 dollars and customer levels results in a total of $8.487 that could be attributed to the D2K program. Based on the Company's estimate of $7 million for the new reliability initiatives, the cost of reliability initiatives appears to be declining. For purposes of my analyses, I assumed that this was a "wash". Therefore, I have escalated the 2000 Distribution operating and maintenance expenses to 2002 dollars using the GDP deflator and a customer growth factor. I then added back the benefits loading adjustment and subtracted the Company's estimated merger-related savings. The result is a Test Year operating and maintenance expense of $82.168 million—which is $15 million less than the Company's Test Year projection.

If the Company's 2001 Budget is used as a starting point, the overstatement in Test Year expenses appears even greater. The 2001 Distribution expense budget was $74.7 million. This budget already included the benefits loading change. Escalating this budget to 2002 based on GDP and customer growth forecasts would derive a 2002 estimated budget of $78.3 million before merger-related synergies and $72.8 million after the merger-related synergies. This is $24.3 million less than the Company's projected Test Year distribution budget, yet the only explanation given by the Company for the large increase in distribution expenses from 2000 to 2002 was the "new and expanded Reliability/System Integrity Program" (Schedule C-21, page 7 of 8), which is estimated to cost $7 million in 2002.

STORM DAMAGE EXPENSE AND RESERVE

Q: HOW HAS THE COMPANY TREATED THE RESERVE FOR STORM DAMAGE EXPENSE?

A: The Company has continued to accrue $6 million to the storm damage fund, as authorized in Order No. PSC-94-0852-FOF-EI. They have further assumed that the amount charged to the reserve for storm damage will be equal to the accrual.

Q: DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S CONTINUATION OF THE $6 MILLION STORM DAMAGE ACCRUAL?

A: Yes. Given the current balance in the storm damage account and the Company's historical storm damage experience, I believe the Commission should re-visit the level of annual accrual to the storm damage fund. In response to Citizens' Interrogatory No. 92, the Company provided its storm damage charges for 1997 through 2000. Table 6 below shows the annual charges and the average of those charges.

TABLE 6 STORM DAMAGE EXPERIENCE 1997-2000	
Year	Charge ($ Thousands)
1997	$1,159
1998	$0
1999	$4,506
2000	$2,103
Average	$1,942

In a Commission Memorandum dated September 30, 1993 in Docket No. 930867-EI, the Commission noted that FPC's average annual storm loss history was $.7 million using a 20 year period and $1.4 million over the most recent 10 years. As of December 31, 2001, the Company is estimating a storm damage fund balance of $32 million. Assuming that storm damages average $2 million a year, the fund is now sufficient to cover 16 years of average storm damages. If the storm damage accrual is reduced to an estimated storm damage of $2 million, the accruals would be sufficient to pay for normally-anticipated storm damages. This would allow FPC to retain the full $32 million for more severe damage. This adjustment would reduce the total system revenue requirement by $4 million and the retail customers' revenue requirement by $3.879 million.

Q: IF THE COMMISSION ALLOWS FPC TO CONTINUE ACCRUING $6 MILLION A YEAR FOR STORM DAMAGES, SHOULD THE COMPANY'S RECOMMENDED RATE BASE OFFSET BE ADJUSTED?

A: Yes. As explained above, the Company has assumed that the amount charged to the storm damage fund will be equal to the $6 million expense accrual, thereby limiting the rate base offset to the amount accrued as of December 31, 2001. Allowing charges based on the average storm damage costs experienced from 1997 through 2000 would reduce the charges from $6 million to $2 million. This reduction would increase the Property Insurance Reserve balance by $4 million. Account 190 accumulated deferred income taxes would increase by the taxes on the $4 million, or $1.543 million, resulting in a total rate base adjustment of $2.457 million. This adjustment would decrease the total system revenue requirement by $392,320, assuming FPC's proposed return on equity of 13.2%. The retail jurisdiction revenue requirement would be decreased by $380,485.

POWER MARKETING EXPENSES

Q: DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S TREATMENT OF SALES EXPENSES IN THE TEST YEAR?

A: Yes. The Company has estimated Power Marketing expenses of $4.897 million in the 2002 Test Year, which is an increase of 89.7% from the expense incurred in 2000, indicating an annual growth of 37.7%. This amount has been allocated 100% to the retail jurisdiction. Aside from the large increase in Power Marketing expenses, I have two concerns with the allocation of the costs. First, FPC has failed to allocate any portion to the wholesale jurisdiction, yet these customers benefit from the economy sales in the same manner as the retail customers. Second, FPC has not absorbed any of the cost increase, yet FPC enjoys a 20% incentive on the margins created from increases in sales over the historical 3 year average. This incentive was established in Order No. PSC-00-1744-PAA-EI and was described on page 10 of the Order:

> Therefore, we find that a three year moving average of the gains on non-separated sales, firm and non-firm, excluding emergency sales, is an appropriate threshold for the shareholder incentive. All gains at or below this threshold shall be credited to the ratepayers. All gains above this threshold shall be split 80%/20% between ratepayers and shareholders, respectively.

In addition, as explained earlier, the Company is expecting substantial benefits from expanded competitive wholesale sales. It is not clear whether the Power Marketing expenses included in the Test Year sales expenses include costs associated with the Company's attempts to expand its competitive wholesale business. In the preliminary issues summary, October 29, 1999 (OPC 010159), it was noted that, at that time, FPC was projecting in excess of $4 million per year in "below the line" profits from off-system trading. On Attachment 5 of the November 30, 1999 synergies report for Power Operations, Power Trading and Term Marketing (OPC 010182), the Company indicated that FPC Trading Center costs were borne by the shareholders and trading margins that involved FPC's regulatory assets go to the customers, while at CP&L, trading margins are retained by the shareholders and retail customers are "made whole". The noted desired outcome was for FPC to get treatment similar to CP&L. The "fallback outcome" was that FPC could recover all of its Power Marketing costs and keep a portion of its trading margin. As noted above, FPC has already accomplished a portion of the fallback outcome through the Commission's Order No. PSC-00-1744-PAA-EI allowing the sharing of increased margins. In this case, FPC is attempting to achieve the remainder of its fallback outcome by recovering all of the Power Marketing costs from the retail customers.

Q: WHAT METHOD OF ALLOCATION ARE YOU PROPOSING FOR THE POWER MARKETING EXPENSES?

A: Although it appears that the Power Marketing expenses may include expenses related to expansion of FPC's non-regulated wholesale sales, I do not have sufficient information to verify this or to provide a breakdown the Power Marketing expenses of $4.897 million into the various services provided by this department; therefore, I am limiting my adjustment to an allocated share of the Power Marketing expenses to the shareholders, to the extent of the opportunity for the sharing of margins, and to the wholesale average rate customers. Since gains from sales are credited to the customers based on a three year moving average, I would propose to allocate 20% of the increase in 2002 Power Marketing expenses over the three year average from 1999 through 2001. Based on the information provided in Schedule C-12, page 8 of 13, the average Power Marketing expenses over 1999 through 2001 were $2.512 million. The 2002 increase over the three year average is thus $2.385 million. Allocating 20% of the $2.385 million to the shareholders provides a reduction in the total system revenue requirement of $477,000. The remainder of the Test Year Power Marketing expense of $4.420 million would then be allocated to both the wholesale and retail jurisdictions, excluding stratified wholesale sales, which have specifically defined fuel costs. Based on FPC's energy allocator for average rate sales, Factor K306, 97.646%, or $4.316 million, of the total costs would be borne by the retail customers. This adjustment reduces the retail customers' revenue requirement by $581,000.

Last Core Nuclear Fuel and End-of-Life Materials and Supplies

Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR AMORTIZING THE LAST CORE NUCLEAR FUEL.

A: The Company is proposing to amortize the last core of nuclear fuel in the Crystal River 3 nuclear unit over the 15-year remaining life of the plant. The cost to the retail customers is $1.172 million a year. The Commission addressed this issue in Order PSC-02-0055-PAA-EI and concluded that the associated costs should be considered a base rate future obligation and recommended the amortization of the Last Core costs as a base rate fuel expense with a credit to an unfunded Account 228 reserve.

Q: DO YOU BELIEVE THE AMORTIZATION OF THE LAST CORE SHOULD BE STARTED AT THIS TIME?

A: No. As noted in the response to FIPUG Interrogatory No. 10, FPC has already notified the NRC of plans to evaluate license extension and has committed to advising the NRC of its decision the end of the fourth quarter, 2005. In Order PSC-02-0055-PAA-EI, the Commission recognized that uncertainties surrounding the timing of unit shut down, the actual costs associated with the Last Core, and the future regulatory environment were all factors that led them to believe that the associated costs should be considered a base rate future obligation. The Commission directed FPC to address costs associated with the Last Core in subsequent decommissioning studies so that the annual accruals could be revised, if warranted.

In the May 2001 National Energy Policy, the National Energy Policy Development Group ("NEPD Group") noted that:

> Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed. (National Energy Policy, May, 2001, page 5-15)

The NEPD Group, went on to recommend that the President support the expansion of nuclear energy in the United States and made a specific recommendation to:

> Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards. (National Energy Policy, May, 2001, page 5-17)

On December 4, 2001, Dr. Richard A. Meserve, Chairman of the Nuclear Regulatory Commission ("NRC"), spoke at the Energy Investor Policy and Regulation Conference regarding the nuclear power industry. When addressing nuclear plant license extensions, Dr. Meserve explained:

> The question for the nation's nuclear generators is this: Given the current performance level of the nation's nuclear plants, and giving what is known about alternative energy sources and their costs, should they shutdown their existing plants or instead seek to exploit them further? Not surprisingly, the answer is that, far from abandoning those plants, the generators, virtually without exception, should seek to extend the original 40-year license terms. Several have already obtained 20-year license extensions; others are in the process of doing so: and applications from many other generators, possibly all of them, are expected. (What the National Energy Strategy Means for the Nuclear Power Industry, NRC News, http://www.nrc.gov/OPA, Section V)

Given FPC's expectation of filing for a license extension and the National Energy Policy and NRC's expressed support of such extensions, it appears likely that the CR3 license will be extended to 2036. Beginning amortization at this time thus appears premature.

In his comments, Dr. Meserve also noted that the NRC set a 30-month schedule for review of license renewal applications and had been able to meet or beat that timetable in each case without sacrificing quality. Thus, even if FPC waited until the fourth quarter of 2005 to apply for license extension, the extension could be expected sometime in 2008, leaving 8 years to amortize the last core if the extension is rejected, and a full 28 years to amortize the last core if a 20 year extension is granted. Elimination of the Last Core amortization in this proceeding would decrease the retail customers' revenue requirement by $1.172 million.

If the Commission chooses to allow FPC to begin amortization at this time, based on the decision set forth in Order PSC-02-0055-PAA-EI, then, at a minimum, the Commission should reconsider the length of the amortization period. Recognizing the probability of license extension, the amortization could be extended over a 35-year period. As directed by the Commission, FPC could then address required modifications to the amortization in its future decommissioning studies, thus allowing for increasing the amortization in the event that license extension is not granted. To amortize the Last Core over a 35-year period, I have followed the Company's methodology which was set forth in its response to Citizens' Interrogatory No. 61. I escalated the cost of the Last Core for an additional 20 years, resulting in a future Last Core cost of $26.911 million. Amortization of this level of Last Core cost over a 35-year period would be $769,000. The rate base offset for the Account 228 balance, net of accumulated deferred income taxes, would be decreased to reflect the lower amortization. The combined effect of this adjustment would be a reduction in total system revenue requirements of $412,000. The reduction in the retail customers' revenue requirement would be $402,000.

Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR AMORTIZING THE NUCLEAR END-OF-LIFE MATERIALS AND SUPPLIES BALANCE.

A: As with the Last Core amortization, the Company is proposing to amortize the projected balance of materials and supplies that will be on-hand at the end of the CR3 license life. FPC originally estimated this amount to be $25 million and thus included $1.667 million in amortization over the 15 year period. Subsequently, FPC reduced this amount to $22 million, with an annual amortization of $1.467 million. This reduction has not been reflected in FPC's Schedule E cost of service studies.

Q: DO YOU HAVE ANY CONCERNS WITH FPC'S PROPOSED AMORTIZATION?

A: Yes. The Commission addressed the End-of-Life Nuclear Materials and Supplies balance in Order PSC-02-0055-PAA-EI, concluding that it was appropriate to amortize these costs over the remaining life of the nuclear facility to ratably allocate the costs to those receiving the benefit of the generated power. The Commission found that the amortization expense should be debited to nuclear maintenance expense and credited to an unfunded Account 228 reserve. For the same reasons as explained above on the Last Core issue, I believe that beginning the materials and supplies amortization at this time is premature. Elimination of the amortization would reduce the total system revenue requirement by $1.667 million (including the original overstatment of $.2 million).

Again, as an alternative, the materials and supplies should be amortized over a 35-year period. Since the materials and supplies are already in inventory, there would be no escalation in value over the remaining life; therefore, the amortization would be reduced to $628,571. In addition, the rate base offset for Account 228, net of accumulated deferred income taxes, would be decreased. The combined effect of this adjustment would be a decrease in the total system revenue requirement of $801,000 (assuming the original overstatement is already corrected) and the retail customers' revenue requirement of $769,000.

Transmission Operating and Maintenance Expenses

Q: PLEASE DESCRIBE THE COMPANY'S TEST YEAR PROJECTION OF TRANSMISSION EXPENSES.

A: The Company is projecting total transmission expenses of $34.288 million for the Test Year, after reflection of $1.5 million in estimated merger-related synergies. This is an annual increase of 6.8% a year including the estimated merger-related synergies and 9.1% a year if those synergies are not included. In 1999 and 2000, the Company had expenses of $9.7

million and $5.4 million for Account 565, Transmission of Electricity by Others. This expense is not expected to continue in 2002 due to termination of the Seminole Electric wholesale contract in December, 2001. If these amounts are removed from the 1999 and 2000 expenses, the annual rate of increase to the Company's projected Test Year Transmission expenses is 13.2% and 17.9%, respectively. Before the estimated offsets for merger-related synergies, the annual rate of increase would be 14.8% based on 1999 expenses and 20.5% based on 2000 expenses.

Q: WHAT REASONS HAS THE COMPANY PROVIDED FOR THIS HIGH LEVEL OF INCREASE IN TRANSMISSION EXPENSES?

A: As explained by FPC's Witness Rogers:

> ....the time has come when we must replace deteriorating poles, cross arms, insulators, and other aging facilities because the Company's transmission facilities are the arteries of the utility's electric service system. Therefore, we are budgeting expenditures for 2002 that are reasonably necessary to maintain this system in good working order in future years...we have identified a number of areas where we must replace or repair transmission equipment to be prepared fully to meet the demands of the new millennium. But more than that, we are committed to providing proactive maintenance of substation equipment and other facilities to ensure continuing reliability in future years. (Rogers, page 4)

Witness Rogers goes on to explain FPC's reliability initiatives, including the need to repair or replace some of the substation breakers, defective substation equipment, poles and other equipment, and that FPC is committed to accomplishing the needed repairs and replacement over a three-year time period. Exhibit SSR-1 sets forth a summary of FPC's planned reliability initiatives and the operating and maintenance expenses and capital costs associated with those initiatives over the three-year time period, beginning with the Test Year. As shown on Exhibit SSR-1, the Company is projecting $9.73 million in operating and maintenance expenses for reliability initiatives during the Test Year. This $9.73 million would fully explain the large increases in Transmission expenses from 2000 to 2002; however, given the Company's reduction in employees, any portion of the $9.73 million related to labor costs would not be incremental costs, but would simply be shifting the responsibilities of employees whose costs were already included in the 2000 transmission expenses.

Q: DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S TEST YEAR PROJECTION OF TRANSMISSION OPERATING AND MAINTENANCE EXPENSES?

A: Yes. Table 7 below shows a breakdown of the Test Year operating and maintenance expenses due to the Company's planned reliability initiatives.

TABLE 7
FPC TEST YEAR TRANSMISSION O&M EXPENSES FOR RELIABILITY INITIATIVES

RELIABILITY INITIATIVE	($000'S)
Renovate and Modernize Substations	$1,700
Upgrade GE Type-U Bushings	$1,700
Vegetation/Encroachment Mgmt	$4,500
Inspection and Repair of Wood Poles	$1,000
Repair of Transmission Structures	$ 580
Install Diagnostic Monitors	$ 250
Total Test Year Expenses	$9,730

The Company projects that this level of Transmission expenses will be incurred for each year from 2002 to 2004 for the implementation of the reliability initiatives.

While these repairs and upgrades may be necessary or desirable, it is clear that such initiatives are planned to increase reliability, not just for the immediate three-year period, but far into the future. Witness Rogers testified that FPC's system was installed in the 1950s, 1960s, and 1970s and that it is now showing signs of age. Thus it has served the customers for 30 to 50 years. These reliability improvements will obviously provide benefits for years to come. In addition, it is likely that a regional transmission organization ("RTO") will be formed and, at this time, the method of cost recovery under such an RTO and resulting impact on the retail customers is not known. Further, it appears that many of these initiatives are playing "catch up" for maintenance that could have been done on a proactive basis, perhaps at lower costs. Witness Rogers notes that this plan will enable the Company to focus on preventive maintenance, rather than merely reactive maintenance. For all of these reasons, I believe the costs of the reliability initiatives should be either capitalized as a component of the associated capital costs or amortized over a longer period of time.

Q: HAVE YOU DEVELOPED A RECOMMENDED METHOD OF AMORTIZING THE COSTS OF THE RELIABILITY INITIATIVES?

A: Yes. Although many of these initiatives are related to capital improvements that will depreciated over a much longer life, I have limited the amortization to a 10 year period. Based on the expected total expenditures of $29.19 million over the three-year period, the annual amortization of the total reliability initiatives would be $2.919 million. In the Test Year, this would result in deferral of $6.811 million for collection in later years; therefore, I would increase rate base by the average Test Year deferral of $3.406 million, net of deferred income taxes of $1.314 million. The net impact of this adjustment is a decrease of $6.51 million in the total system revenue requirement and $4.727 million in the retail customers' revenue requirement.

TIGER BAY ACCELERATED AMORTIZATION

Q: PLEASE DESCRIBE THE TREATMENT OF THE TIGER BAY REGULATORY ASSET.

A: In Order No. PSC-97-0652-S-EQ, the Commission approved a stipulation allowing FPC to recover its costs of acquiring the Tiger Bay cogeneration facility. The first $75 million of the costs were placed in rate base, to be depreciated. The remainder of the purchase price was treated as a Regulatory Asset. The Commission approved a methodology of amortizing the Tiger Bay Regulatory Asset by the difference between the continuation of charges that would have been otherwise incurred through purchased power adjustments if the facility had not been purchased, net of actual fuel charges incurred. At that time, FPC projected that the asset would be fully amortized by January, 2008, using this methodology. The Commission also allowed FPC to accelerate the amortization of the Tiger Bay Regulatory Asset on a discretionary basis from its earnings.

Subsequent to Order No. PSC-97-0652-S-EQ, FPC's earnings were excessive and the Commission approved FPC's application of excess earnings to the accelerated amortization of the Tiger Bay Regulatory Asset. Accelerated amortization included $14 million in 1998, $10.3 million in 1999, $48.5 million in 2000, and $63 million in 2001. In addition, as explained by Witness Javier Portuondo on page 5 of his testimony, the Company is projecting additional accelerated amortization of $30 million for 2001 and $9 million for 2002 during the pendency of the rate case. Witness Portuondo argued that the amount of funds subject to refund should be reduced by the additional accelerated amortization of $39 million. The Commission subsequently addressed this issue in Order No. PSC-01-2313-PSC-EI and indicated that the refund would be reduced by the actual amount of additional accelerated amortization taken during the refund effective period.

Q: HOW HAS THE COMPANY TREATED THE TIGER BAY REGULATORY ASSET IN THE DEVELOPMENT OF THE TEST YEAR REVENUE REQUIREMENT?

A: The Company is projecting amortization of $40,666,149 through the purchased power collections, less fuel costs, in the Test Year. In addition, the Company has included accelerated amortization of $9 million in the Test Year revenue requirement.

Q: SHOULD THE COMPANY BE ALLOWED TO INCLUDE THE ACCELERATED AMORTIZATION IN THE DEVELOPMENT OF THE TEST YEAR REVENUE REQUIREMENT?

A: No. Order No. PSC-7-0652-S-EQ provided for the Company to apply its earnings to accelerated amortization on a discretionary basis. It did not, however, allow the Company to convert such "excess earnings" to "required earnings" in the development of base rates. Even if the Company projects excess earnings during the refund effective period and projects that an additional $9 million will be applied to the Tiger Bay Regulatory Asset amortization during that time, the Company will be allowed to reduce any refunds by the additional amortization. The additional amortization should not be used in setting rates to be applied prospectively.

In addition, as noted by the Commission in Order No. PSC-7-0652-S-EQ, the advantages of the Stipulation are eroded in this proceeding by the additional revenue requirement associated with the portion of the Tiger Bay cost that is included in rate base. Since the time of Order No. PSC-7-0652-S-EQ, FPC has apparently made additions to the Tiger Bay facility, resulting in a December, 2001 balance of $97.1 million. Five million dollars in further additions are planned in 2002. The Tiger Bay depreciation expense included in the

Test Year revenue requirement is $5.8 million.

Q: WHAT IS THE IMPACT OF ELIMINATING THE $9 MILLION ACCELERATED AMORTIZATION ADJUSTMENT?

A: Since the Tiger Bay Regulatory Asset is not in rate base, the customers will benefit more by reducing ***current*** revenue requirements and extending the amortization period. Given the Company's projected $40 million amortization through the purchased power collections, net of fuel costs, the elimination of the $9 million accelerated amortization adjustment would only extend the time period for the continued collection of the Tiger Bay purchased power costs through the fuel adjustment clause by a few months, with full amortization occurring sometime in 2004. This cost would be automatically eliminated through the fuel adjustment clause, rather than requiring a base rate adjustment at that time.

RATE CASE EXPENSES

Q: HOW HAS THE COMPANY TREATED ITS COSTS ASSOCIATED WITH THIS RATE PROCEEDING?

A: The Company has estimated total costs associated with the current case of $1.644 million and is proposing to amortize those costs over a two-year period.

Q: DO YOU HAVE ANY CONCERNS WITH FPC'S PROPOSAL TO DEFER THE 2001 EXPENSES AND TO AMORTIZE THOSE COSTS OVER A TWO-YEAR PERIOD?

A: Yes. A portion of these costs were incurred in 2001. If these costs are excluded from the 2001 Surveillance Report, FPC's earnings will increase and FPC will then have the discretion as to whether, and to what amount, to include any such increase as additional amortization on Tiger Bay. FPC is already projecting additional Tiger Bay amortization for 2001, indicating expected excess earnings. If the Commission is interested in increasing the

Tiger Bay amortization for 2001, then FPC should only be allowed to exclude the rate case expenses from 2001 to the extent that such amounts are applied to the Tiger Bay amortization. Otherwise, FPC should be required to absorb the 2001 rate case expenses and amortize only the remainder of the expenses that are expected to be incurred in 2002.

Q: DO YOU HAVE SUFFICIENT INFORMATION TO DETERMINE THE LEVEL OF RATE CASE EXPENSES ACTUALLY INCURRED IN 2001?

A: No. The 2001 rate case expenses should be verified as part of this proceeding or as part of the Surveillance Report.

Q: WHAT IS THE APPROPRIATE AMORTIZATION PERIOD FOR THE RATE CASE EXPENSES?

A: In the last FPC rate case, the Commission required FPC to amortize its rate case expenses over a 4 year period, since rates were expected to be in effect for at least that period of time. Given the length of time that has actually expired between the last rate case and the current proceeding, it would be appropriate to again allow the amortization over a 4 year period.

Q: PLEASE DESCRIBE THE ALTERNATIVE METHODOLOGIES YOU ARE PROPOSING.

A: For purposes of demonstration, assuming that one-half of the estimated expenses were incurred in 2001, the expenses would either i) be recognized in the 2001 Surveillance Report and absorbed by FPC, with the balance of $822,000 amortized over 4 years at $205,500 a year, thereby reducing the retail customers' revenue requirement by $616,500 or ii) be removed from 2001 expenses, increasing the excess revenues that would be applied to the Tiger Bay accelerated amortization and allowing the total rate case expenses of $1.6 million to be amortized over 4 years at $411,000 a year.

COST ALLOCATION

Q: WITNESS SLUSSER HAS RECOMMENDED THAT THE COST ALLOCATION METHODOLOGY IN THIS PROCEEDING SHOULD BE SHIFTED FROM THE HISTORICALLY-USED 12CP AND 1/13 AVERAGE DEMAND METHOD TO THE 75 PERCENT DEMAND AND 25 PERCENT ENERGY METHODOLOGY. WHAT IS WITNESS SLUSSER'S JUSTIFICATION FOR MODIFYING THE ALLOCATION METHODOLOGY?

A: Witness Slusser explains that energy utilization is a major consideration in the type of plants considered to be built. Base load plants are typically more capital intensive, but the higher capital costs are typically justified by the lower energy costs and higher expected energy utilization.

Q: DID WITNESS SLUSSER PROPOSE TO ADJUST THE ALLOCATION METHODOLOGY USED FOR THE ASSIGNMENT OF ANY OTHER COSTS?

A: Yes. Witness Slusser has also proposed adjusting the allocation of capacity costs in both the Capacity Cost Recovery Clause and the Energy Conservation Cost Recovery Clause.

Q: SHOULD THE COMMISSION ALLOW FPC TO MODIFY THE ALLOCATION METHOD IN THIS PROCEEDING?

A: No. While Witness Slusser is correct in his contention that a portion of FPC's production facilities were constructed to provide low-cost energy, the proposed allocation will only address half of the issue. Since high load factor customers have a better utilization of energy relative to the demands placed on the system, Witness Slusser's recommended change in allocation methodology would shift costs to the high load factor customers. Under the fuel adjustment practices, FPC's customers pay for their energy based on average system costs. Since a greater portion of high load factor customers' energy requirements come from base energy, the high load factor customers are, in effect, subsidizing the low load factor customers through the fuel adjustment charges. To change the allocation methodology for production plant without changing the corresponding allocation of fuel costs would unfairly penalize the high load factor customers.

ALLOCATED COST OF SERVICE AND RECOMMENDED REVENUE REQUIREMENTS

Q: HAVE YOU DUPLICATED THE COMPANY'S TEST YEAR COST OF SERVICE STUDY?

A: Yes. Exhibit SLB-3 is a copy of the cost of service model I developed to evaluate the Company's Test Year revenue requirements. This model was developed to reflect the Total System allocations, as well as the retail jurisdiction revenue requirement and allocations under the Company's 75% Demand/25% Energy cost allocation case, which they have treated as their "Base Case".

Q: DOES EXHIBIT SLB-3 REFLECT THE MODIFICATIONS REQUESTED BY WITNESS MYERS IN HIS NOVEMBER 15, 2001 TESTIMONY?

A: No. I tested the Company's recommended adjustments by modifying the Total System and Total Retail Jurisdiction classes in my cost of service model; however, since the Company has not provided a breakdown of the total revenue reduction by rate class, I did note incorporate the Company's adjustments in Exhibit SLB-3 for purposes of my analyses. In the event that the Commission accepts the Company's recommended adjustments, the net effect on each class' revenue requirement would require a detailed breakdown of the revenue adjustments by class.

Q: HAVE YOU DEVELOPED A REVISED COST OF SERVICE STUDY REFLECTING ALL THE ADJUSTMENTS YOU HAVE RECOMMENDED HEREIN?

A: Yes. Exhibit SLB-4 is a copy of the revised cost of service study. Table 8 below summarizes Exhibit SLB-4 and shows the breakdown of the revenue requirements and rate reductions associated with each class.

TABLE 8
SUMMARY OF REVENUE REQUIREMENTS
AND RECOMMENDED RATE REDUCTIONS

Rate Class	Present Base Revenues	Revenue Requirements Per FPC	Revised Revenue Requirement	Required Rate Reduction (Increase)	Percent Rate (Reduction) or Increase
Residential	886,989	884,878	796,734	90,255	(10.18%)
GSND	61,766	52,948	46,765	15,001	(24.3%)
GS 100% LF	2,542	2,843	2,479	63	(2.48%)
GSD	359,989	358,876	312,287	47,702	(13.3%)
Curtailable	4,114	3,770	3,157	957	(23.3%)
Interruptible	44,335	47,277	40,269	4,066	(9.17%)
Lighting Energy	5,283	5,715	4,522	761	(14.4%)
Lighting-FM	21,929	26,341	23,720	-1,791	+8.17%
Lighting Poles	10,299	14,619	12,963	-2,664	+25.87%
Total Retail	1,397,246	1,397,267	1,242,896	154,350	(11.05%)

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

Position	Managing Principal
Education	B.S. in Accounting University of West Florida Pensacola, Florida M.B.A. University of Central Florida Orlando, Florida
Professional and Business History	SVBK CONSULTING GROUP 1985 - Present R.W. Beck & Associates 1981 - 1985

Professional Experience

Ms. Brown has extensive experience in the emerging deregulation of the electric industry. She has provided expert testimony on behalf of clients on such issues as stranded cost calculation and recovery, market pricing, and public policy. In participating in deregulation proceedings, Ms. Brown has been responsible for the preparation of comments to regulatory commissions regarding policy issues on restructuring. She has participated in technical conferences held to set policy issues and assisted legal counsel in the preparation of legal positions regarding previous rate agreements and other agreements entered into relevant to the proceedings. In her experience, Ms. Brown has been responsible for the development of methodologies for determining and recovering interim stranded costs. Ms. Brown has also been called on to participate in panel discussions before the regulators regarding the many issues relative to the deregulation of the electric industry.

Mrs. Brown serves as a member of the Association of Higher Education Facilities'Energy Task Force on deregulation issues. Further, she has been responsible for positioning clients to actively and successfully participate in a Retail Wheeling Pilot Program. In her capacity as lead financial consultant, Ms. Brown assisted in public information campaigns to encourage volunteers, filed comments with regulators to influence the selection process, and developed an aggregation program for eligible Pilot Program participants.

Ms. Brown has developed qualified aggregation programs and participated in public workshops to encourage eligible businesses and residents to participate in municipal aggregation programs. Ms. Brown has negotiated and evaluated power supply arrangements for municipal electric systems, universities, and retail aggregation programs. Such negotiations have included joint ownership arrangements, block power purchases combined

Professional Experience

with supplemental partial requirements, formula rate contracts, economy purchases, full requirements and partial requirements combined with self-generation. She has evaluated the economic feasibility of peaking generating facilities and has negotiated terms and conditions with the electric supplier to enhance the economic benefits of peaking operations.

Ms. Brown has extensive experience in wholesale and retail ratemaking and has represented numerous municipal, cooperative, university, and regulatory clients in proceedings before the Federal Energy Regulatory Commission and various state and local commissions. She has negotiated the settlement of rate cases and has presented expert testimony as a witness in litigated proceedings. As an expert witness, Ms. Brown has presented testimony on revenue requirement issues, cost-of-service studies and allocation methodologies, rate design, utility valuations, and terms and conditions of service.

Ms. Brown has also developed cost recovery methodologies for least cost integrated resource programs, including the effects of demand side management programs on interim recovery of fixed costs. She has additionally developed innovative rate structures designed to provide performance based incentives for demand side management performance.

Ms. Brown has evaluated the effects of capacity and transmission equalization under combined utility operations and the allocation of costs under joint dispatch arrangements. She has provided expert testimony on the effects of a proposed merger on individual utility operations.

Ms. Brown has performed numerous retail rate studies, including the development of revenue requirements, allocated cost-of-service studies, and rate design. She has developed load forecasts using econometric modeling and has developed proforma operating results for rate phase in plans. She has additionally reviewed transfer policies and interdepartmental service contracts.

Ms. Brown has performed feasibility studies for the installation and operation of cogeneration facilities. She has evaluated the benefits of retaining cogeneration to offset retail electric requirements. She has also evaluated the requirements for standby service or reserves. Ms. Brown has successfully challenged the development of standby rates and terms and conditions of service, resulting in enhanced cogeneration project value. She has performed avoided cost calculations and has negotiated arrangements to sell cogeneration capacity and energy to the electric supplier. In addition, she has reviewed market alternatives to selling cogeneration capacity and energy for resale, including the effect of transmission arrangements on project viability.

Professional Experience

Ms. Brown has negotiated the sale or purchase of utility systems or facilities, including the purchase or sale agreements; management, operating, and maintenance agreements, and design/construction agreements. She has enhanced project value by negotiating contractual guarantees, including operational efficiency and price guarantees. She has additionally negotiated long term gas supply contracts and financial hedging instruments, including SWAP agreements. She has negotiated transportation contracts, including banking arrangements, whereby excess contract gas is sold back to the transporter at market rates.

Ms. Brown has served on municipal strategic planning committees and has provided capital budgeting analyses for the evaluation of long-term planning alternatives. She has been extensively involved in the development of utility system management studies, including the review of labor costs and efficiencies, organization structure and financial condition. She has additionally performed billing audits.

Regulatory Appearances

Federal Energy Regulatory Commission ("FERC")
Council of the City of New Orleans ("CCNO")
Louisiana Public Service Commission ("LPSC")
Massachusetts Department of Telecommunications & Energy ("DTE")
Minnesota Public Utilities Commission ("MPUC")
New Hampshire Public Utilities Commission ("NHPUC")
North Carolina Utilities Commission ("NCUC")
Texas Public Utilities Commission ("TPUC")

Papers, Publications, and Presentations

"Municipalization/Franchise Evaluation" - Panel presentation to the Tri-County League of Cities, Casselberry, Florida, January, 2001.

"Opportunities and Challenges: Managing Energy Costs in a Deregulated Environment" - Presented to the Dallas Chapter of the National Association of Purchasing Managers, Dallas, Texas, October, 2000.

"Unbundling - Identifying Strategies for a Smooth Transition to Competition" - Presented at the South Carolina Association of Municipal Power Systems Annual Conference, Hilton Head, South Carolina, June, 1999.

"Preparing for Deregulation - Understanding Electric Restructuring Issues Affecting Local Government" - Presented at the Taking Control of Your Destiny: Assessing the Impact of Electric Utility Industry Deregulation on Local Government Conference, Minneapolis, Minnesota, June, 1999.

"Electric Restructuring and Utilities Deregulation: A Facility Manager's Guide" - Coauthor with the APPA Energy Task Force, The Association of Higher Education Facilities Managers, Alexandria, Virginia, 1998.

"Utilities and You: A New Playing Field" - Presented at the U.S. Department of Energy Rebuild America 1998 Annual Conference, San Antonio, Texas, March 1998.

"Preparing for Deregulation in the Electric Utility Industry" - Presented at the Municipal Association of South Carolina 1998 Winter Meeting, Columbia, South Carolina, February, 1998.

"Electric Utility Deregulation" - Presented at the South Carolina Association of Municipal Power Systems Annual Event, Columbia, South Carolina, April 1997.

"Problems & Solutions in Retail Implementation: An Overview of Issues in Electric Utility Restructuring" - Presented at the Energy Awareness: Competition in Electricity in South Carolina Conference, Columbia, South Carolina, March 1997.

"Municipalization of Electric Utility Systems Seminar" - Presented to the Municipal Association of South Carolina, Columbia, South Carolina, August 1996.

"Opportunities and Challenges Resulting From Restructuring of the Electric Industry" - Presented to the Mayor and Board of Aldermen, City of Nashua, New Hampshire, August 1996.

"Opportunities/Challenges Resulting From Restructuring of the Electric Industry" - Presented to the New Hampshire Municipal Association, Concord, New Hampshire, June 1996.

"Challenges and Opportunities in the College, University, and Institutional Services Market"-Presented to the Confidential Clients, August, 1995 and December, 1995.

"Customer Retention/Attraction Strategies-Developing Responses to Customer Alternatives"-Presented to the American Public Power Association Accounting, Finance, Rates and Information Systems Workshop, Orlando, Florida, September, 1995.

"Seizing the Opportunities - Strategic Utility Planning and Management

Alternatives for Colleges, Universities, and Other Institutions" - Presented as a series of two-day Seminars in San Francisco, Boston and Chicago, 1994.

Papers and Publications

"Seizing the Opportunities - Developing and Executing Long-Range Infrastructure Plans in the 90's" - Presented to the IDHCA College/University Conference, 1993.

"Retail Rate Making and Cost-of-Service Principles" - Presented to the Coalition of Local Governments ("CLG") in St. Petersburg, Florida, 1989.

"A Tale of Two Cities - A Victory for Public Power" - Published by the American Public Power Association ("APPA") in the January/February 1989 issue of Public Power magazine. This article describes the problems and solutions brought about by service territory disputes involving municipally owned electric systems.

"Wholesale Ratemaking and the Effect of Peak Shaving Generation" - Presented to North Carolina and South Carolina Municipalities and Electric Cooperatives, sponsored by Caterpillar, Inc., 1989.

"MMUA Members Set a Model for Resolving Territorial Disputes" - Published by the Minnesota Municipal Utilities Association ("MMUA"), in their monthly periodical News and Views, 1988.

"Takeover Strategy and Evaluation" - Sponsored by the APPA, and presented to the Minnesota Municipal Utilities Association, 1987.

"Is Your System Next?" - Presented to the Wisconsin Municipal Electric Association ("WMEA"). Also presented at the Public Power Week Conference, sponsored by the APPA and the Wisconsin Public Power System, Inc., 1987.

Professional and Business Affiliations

American Institute of Certified Public Accountants
Florida Institute of Certified Public Accountants
American Public Power Association ("APPA")
Association of Higher Education Facilities Managers (formerly Association of Physical Plant Administrators, "APPA")
Florida Government Finance Officers Association

Florida Power Corporation
Distribution O&M Expenses

Exhibit SLB-2

Distribution O&M
(Thousands $)

		1996	1997	1998	1999	2000	2002
580	Supervision & Engineering	2,833	3,389	5,083	4,888	4,256	9,881
582	Station Expenses	240	264	566	516	465	-
583	Overhead Lines	2,634	3,411	2,901	3,233	3,752	19,593
584	Underground Lines	2,076	2,184	2,534	2,947	3,559	3,792
565.02	Street Lighting	0	0	0	0	0	-
586	Meter Expenses	5,059	4,707	5,396	5,370	4,980	8,703
587	Customer Installation	1,242	1,135	1,016	1,181	1,172	1,396
588	Miscellaneous	14,693	17,289	19,093	30,884	32,483	24,000
589	Rents	468	444	493	451	615	361
	Total Operation	29,246	32,824	37,082	49,270	51,282	67,726
590	Supervision & Engineering	609	995	1,094	1,724	1,314	3,082
591	Structures	297	417	321	392	552	357
592	Station Expenses	4,121	4,072	4,055	4,396	4,625	9,037
593	Overhead Lines	14,546	17,321	18,132	14,961	13,476	11,047
594	Underground Lines	1,021	1,031	1,448	1,858	1,734	1,488
595	Line Transformers	777	862	1,011	935	922	1,333
596	Street Lighting	1,521	2,035	2,160	1,957	2,302	2,439
597	Meters	621	588	677	949	816	679
598	Miscellaneous Dist Plant	251	286	236	201	220	-
	Total Maintenance	23,764	27,607	29,134	27,373	25,961	29,442
	Total	53,010	60,431	66,216	76,643	77,243	97,188

1998 Expenses in 1999 Dollars	69,170 [1]		
Change Due to D2K Initiatives	7,473		
Difference Adjusted Up to 2002 Dollars	8,487 [1]		
Cost of New Initiatives per FPC (Schedule C-57d)	7,000 [2]		
1999 and 2000 Expenses in 2002 Dollars with Customer Growth	87,040	84,383 [1]	
Average 1999 and 2000 Expenses in 2002 Dollars with Customer Growth			85,712
Add Back Benefits Loading to Reflect 2001 Accounting Change [3]			1,958
Less Merger-Related Synergies			-5,500
Test Year Adjusted Distribution O&M Expenses			82,168
Test Year Adjustment to Revenue Requirements			-15,000

Footnotes:

[1] Expenses were escalated using GDP (Obtained from Annual Energy Outlook 2001) and Customer Growth (1998 - 2000 obtained from Company's Form 1's and 2002 obtained from Company's 2002 COS Allocator No 8).

Year	Factor	Customers
1998	1.029	1,340,853
1999	1.047	1,376,597
2000	1.070	1,400,299
2001	1.094	1,427,074
2002	1.115	1,468,000

[2] **Initiatives per Schedule C-57d**

Update Fusing Coordination	700
Targeted Feeder Analysis	1,900
Expand Infrared Inspections	300
Feeder Performance Improvement	600
Vegetation Management	1,600
Inspect/Replace Deteriorating Transformers	500
Data Mapping Enhancement	700
Mobile Computer in Service Vehicles	700
Total	7,000

[3] In 2001, the Company shifting Benefit costs from the Administrative and General accounts to the distribution function. The costs associated with this accounting change in 2002 were estimated from the response to OPC No. 82.

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Demand Factors							
1.01	Production Base - % * 1000		104,213	100,000	59,408	2,954	151	32,219
1.02	Ratio To Total Electric		100.00%	95.96%	57.01%	2.83%	0.14%	30.92%
1.03	Prod Intermediate - % * 1000		115,508	100,000	59,408	2,954	151	32,219
1.04	Ratio To Total Electric		100.00%	86.57%	51.43%	2.56%	0.13%	27.89%
1.05	Prod. Peaking - % * 1000		134,117	100,000	59,408	2,954	151	32,219
1.06	Ratio To Total Electric		100.00%	74.56%	44.30%	2.20%	0.11%	24.02%
1.07	Trans Avg 12 Cp - % * 1000		138,667	100,000	62,408	2,881	133	30,095
1.08	Ratio To Total Electric		100.00%	72.12%	45.01%	2.08%	0.10%	21.70%
1.09	Production Base, Retail Only		100,000	100,000	59,408	2,954	151	32,219
1.10	Ratio To Total Electric		100.00%	100.00%	59.41%	2.95%	0.15%	32.22%
	Energy Factors							
2.01	Energy Excl Whol D.A. - % * 1000		102,411	100,000	50,412	3,173	208	38,582
2.02	Ratio To Total Electric		100.00%	97.65%	49.23%	3.10%	0.20%	37.67%
2.03	Energy Excl D.A. Tall - % * 1000		106,312	100,000	50,412	3,173	208	38,582
2.04	Ratio To Total Electric		100.00%	94.06%	47.42%	2.98%	0.20%	36.29%
2.05	Recoverable Fuel - DA Wholesale		65,702	-	-	-	-	-
2.06	Recoverable Fuel - Allocable	2.02	844,314	824,439	415,616	26,159	1,715	318,085
2.07	Total Recoverable Fuel	SUM	910,016	824,439	415,616	26,159	1,715	318,085
2.08	Ratio		100.00%	90.60%	45.67%	2.87%	0.19%	34.95%
	Distribution							
3.01	Distrib Primary - % * 1000		100,473	100,000	63,753	3,595	98	28,038
3.02	Ratio To Total Electric		100.00%	99.53%	63.45%	3.58%	0.10%	27.91%
3.03	Distrib Secondary - % * 1000		100000	100,000	77150	5310	60	16,878
3.04	Ratio To Total Electric		100.00%	100.00%	77.15%	5.31%	0.06%	16.88%
3.05	Distrib Service - % * 1000		100000	100,000	88785	7222	712	3,256
3.06	Ratio To Total Electric		100.00%	100.00%	88.79%	7.22%	0.71%	3.26%
3.07	Distrib Meters - % * 1000		101149.053	100,000	79132	7173	548	12,523
3.08	Ratio To Total Electric		100.00%	98.86%	78.23%	7.09%	0.54%	12.38%
3.09	Distrib Light Fix - % * 1000		100000	100,000	0	0	0	0
3.10	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3.11	Distrib Light Poles - % * 1000		100000	100,000	0	0	0	0
3.12	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3.13	Distrib Is Equip - % * 1000		100000	100,000	0	0	0	0
3.14	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
	Customer Factors							
4.01	Number Of Retail Customers		1467983	1,467,983	1,293,722	104831	10379	47,529
4.02	Ratio To Total Electric		100.00%	100.00%	88.13%	7.14%	0.71%	3.24%
4.03	Meter Reading Exp - % * 1000		100955.035	100,000	86935	7049	612	4,327
4.04	Ratio To Total Electric		100.00%	99.05%	86.11%	6.98%	0.61%	4.29%
4.05	Cust Records Exp - % * 1000		100001	100,000	88129	7141	707	3,238
4.06	Ratio To Total Electric		100.00%	100.00%	88.13%	7.14%	0.71%	3.24%
4.07	Billing Expense - % * 1000		103275.912	100,000	84,930	6911	681	3,382
4.08	Ratio To Total Electric		100.00%	96.83%	82.24%	6.69%	0.66%	3.27%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Demand Factors							
1.01	Production Base - % * 1000		318	4,691	259	-	-	4,213
1.02	Ratio To Total Electric		0.31%	4.50%	0.25%	0.00%	0.00%	4.04%
1.03	Prod Intermediate - % * 1000		318	4,691	259	-	-	15,508
1.04	Ratio To Total Electric		0.28%	4.06%	0.22%	0.00%	0.00%	13.43%
1.05	Prod. Peaking - % * 1000		318	4,691	259	-	-	34,117
1.06	Ratio To Total Electric		0.24%	3.50%	0.19%	0.00%	0.00%	25.44%
1.07	Trans Avg 12 Cp - % * 1000		262	4,125	96	-	-	38,667
1.08	Ratio To Total Electric		0.19%	2.97%	0.07%	0.00%	0.00%	27.89%
1.09	Production Base, Retail Only		318	4,691	259	-	-	-
1.10	Ratio To Total Electric		0.32%	4.69%	0.26%	0.00%	0.00%	0.00%
	Energy Factors							
2.01	Energy Excl Whol D.A. - % * 1000		483	6,391	751	-	-	2,411
2.02	Ratio To Total Electric		0.47%	6.24%	0.73%	0.00%	0.00%	2.35%
2.03	Energy Excl D.A. Tall - % * 1000		483	6,391	751	-	-	6,312
2.04	Ratio To Total Electric		0.45%	6.01%	0.71%	0.00%	0.00%	5.94%
2.05	Recoverable Fuel - DA Wholesale		-	-	-	-	-	65,702
2.06	Recoverable Fuel - Allocable	2.02	3,982	52,690	6,192	-	-	19,875
2.07	Total Recoverable Fuel	SUM	3,982	52,690	6,192	-	-	85,577
2.08	Ratio		0.44%	5.79%	0.68%	0.00%	0.00%	9.40%
	Distribution							
3.01	Distrib Primary - % * 1000		480	3,295	741	-	-	473
3.02	Ratio To Total Electric		0.48%	3.28%	0.74%	0.00%	0.00%	0.47%
3.03	Distrib Secondary - % * 1000		1	147	454	0	0	0
3.04	Ratio To Total Electric		0.00%	0.15%	0.45%	0.00%	0.00%	0.00%
3.05	Distrib Service - % * 1000		0	3	22	0	0	0
3.06	Ratio To Total Electric		0.00%	0.00%	0.02%	0.00%	0.00%	0.00%
3.07	Distrib Meters - % * 1000		22	568	34	0	0	1,149
3.08	Ratio To Total Electric		0.02%	0.56%	0.03%	0.00%	0.00%	1.14%
3.09	Distrib Light Fix - % * 1000		0	0	0	100,000	0	0
3.10	Ratio To Total Electric		0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
3.11	Distrib Light Poles - % * 1000		0	0	0	0	100,000	0
3.12	Ratio To Total Electric		0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
3.13	Distrib Is Equip - % * 1000		0	100000	0	0	0	0
3.14	Ratio To Total Electric		0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
	Customer Factors							
4.01	Number Of Retail Customers		8	148	11,366	0	0	0
4.02	Ratio To Total Electric		0.00%	0.01%	0.77%	0.00%	0.00%	0.00%
4.03	Meter Reading Exp - % * 1000		54	1001	22	0	0	955
4.04	Ratio To Total Electric		0.05%	0.99%	0.02%	0.00%	0.00%	0.95%
4.05	Cust Records Exp - % * 1000		1	10	774	0	0	1
4.06	Ratio To Total Electric		0.00%	0.01%	0.77%	0.00%	0.00%	0.00%
4.07	Billing Expense - % * 1000		12	224	3,860	0	0	3,276
4.08	Ratio To Total Electric		0.01%	0.22%	3.74%	0.00%	0.00%	3.17%
								Check Column

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
5.01	Transmission Plant							
5.02	Generation Step-Up Base	1.02	16,063	15,414	9,157	455	23	4,966
5.03	Generation Step-Up Intermediate	1.04	3,182	2,755	1,637	81	4	888
5.04	Generation Step-Up Peaking	1.06	15,622	11,648	6,920	344	18	3,753
5.05	Transmission	1.08	925,774	667,622	416,649	19,234	888	200,921
5.06	Total Transmission	SUM	960,641	697,438	434,363	20,115	933	210,527
5.07	Ratio		100.00%	72.60%	45.22%	2.09%	0.10%	21.92%
6.07	Distribution Plant							
6.08	Primary	3.02	1,171,725	1,166,206	743,491	41,925	1,143	326,981
6.09	Secondary	3.04	807,905	807,905	623,299	42,900	485	136,358
6.10	Services	3.06	327,389	327,389	290,672	23,644	2,331	10,660
6.11	Meters	3.08	138,081	136,512	108,025	9,792	748	17,095
6.12	Lighting Fixtures	3.10	122,903	122,903	0	0	0	0
6.13	Lighting Poles	3.12	74,247	74,247	0	0	0	0
6.14	IS Equipment	3.14	1,958	1,958	0	0	0	0
6.15	Total Distribution	SUM	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
6.16	Ratio		100.00%	99.73%	66.77%	4.47%	0.18%	18.57%
7.01	Customer Accounting							
7.02	Meter Reading	4.04	10,910	10,807	9,395	762	66	468
7.03	Customer Records	4.06	42,806	42,806	37,724	3,057	303	1,386
7.04	Billing	4.08	8,119	7,861	6,677	543	54	266
7.05	Total Customer Accounting	SUM	61,835	61,474	53,796	4,362	422	2,120
7.06	Ratio		100.00%	99.42%	87.00%	7.05%	0.68%	3.43%
	Wages And Salaries							
8.01	Prod. Demand - Base	1.02	43,590	41,828	24,849	1,236	63	13,476
8.02	Prod. Demand - Intermediate	1.04	7,416	6,420	3,814	190	10	2,069
8.03	Prod. Demand - Peaking	1.06	4,267	3,182	1,890	94	5	1,025
8.04	Production Energy - D.A.Wholesale	DA	991	0	0	0	0	0
8.05	Production Energy-Allocable	2.02	31,257	30,521	15,386	968	63	11,776
8.06	Transmission	5.07	12,797	9,291	5,786	268	12	2,805
8.07	Distribution	6.16	42,548	42,434	28,408	1,903	76	7,902
8.08	Total Ptd Wages & Salaries	SUM	142,866	133,676	80,134	4,659	229	39,052
8.09	Wtd Ptd Wage & Sal Ratios		100.00%	93.57%	56.09%	3.26%	0.16%	27.34%
8.10	Customer Accounting	7.06	14,715	14,629	12,802	1,038	100	504
8.11	Customer Serv & Info. Sales	4.02	3,505	3,505	3,089	250	25	113
8.12	Eccr	4.02	6,013	6,013	5,299	429	43	195
8.13	Total PTDCSS Wages & Salaries	SUM	167,099	157,823	101,324	6,376	397	39,865
8.14	Wtd PTDCSS Wage & Sal Ratios		100.00%	94.45%	60.64%	3.82%	0.24%	23.86%
8.15	Administrative & General	8.14	8,342	7,879	5,058	318	20	1,990
8.16	Total Wages And Salaries Exp	SUM	175,441	165,701	106,383	6,695	417	41,855
8.17	Wtd Wage And Salary Ratios		100.00%	94.45%	60.64%	3.82%	0.24%	23.86%
8.18	Retail Only Wage and Salary Ratios		100.00%	100.00%	64.20%	4.04%	0.25%	25.26%
9.01	Present Class Revenues	DA	1,509,008	1,397,246	886,989	61,766	2,542	359,989
9.02	Present Revenue Ratios		100.00%	92.59%	58.78%	4.09%	0.17%	23.86%
9.03	Retail only Ratios		100.00%	100.00%	63.48%	4.42%	0.18%	25.76%
10.01	Direct Assignment Wholesale		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
5.01	Transmission Plant							
5.02	Generation Step-Up Base	1.02	49	723	40	0	0	649
5.03	Generation Step-Up Intermediate	1.04	9	129	7	0	0	427
5.04	Generation Step-Up Peaking	1.06	37	546	30	0	0	3,974
5.05	Transmission	1.08	1,749	27,539	641	0	0	258,152
5.06	Total Transmission	SUM	1,844	28,938	718	0	0	263,203
5.07	Ratio		0.19%	3.01%	0.07%	0.00%	0.00%	27.40%
6.07	Distribution Plant							
6.08	Primary	3.02	5,598	38,426	8,642	0	0	5,519
6.09	Secondary	3.04	8	1,188	3,668	0	0	0
6.10	Services	3.06	0	10	72	0	0	0
6.11	Meters	3.08	30	775	46	0	0	1,569
6.12	Lighting Fixtures	3.10	0	0	0	122,903	0	0
6.13	Lighting Poles	3.12	0	0	0	0	74,247	0
6.14	IS Equipment	3.14	0	1,958	0	0	0	0
6.15	Total Distribution	SUM	5,636	42,357	12,428	122,903	74,247	7,087
6.16	Ratio		0.21%	1.60%	0.47%	4.65%	2.81%	0.27%
7.01	Customer Accounting							
7.02	Meter Reading	4.04	6	108	2	0	0	103
7.03	Customer Records	4.06	0	4	331	0	0	0
7.04	Billing	4.08	1	18	303	0	0	258
7.05	Total Customer Accounting	SUM	7	130	637	0	0	361
7.06	Ratio		0.01%	0.21%	1.03%	0.00%	0.00%	0.58%
	Wages And Salaries							
8.01	Prod. Demand - Base	1.02	133	1,962	108	0	0	1,762
8.02	Prod. Demand - Intermediate	1.04	20	301	17	0	0	996
8.03	Prod. Demand - Peaking	1.06	10	149	8	0	0	1,085
8.04	Production Energy - D.A.Wholesale	DA	0	0	0	0	0	991
8.05	Production Energy-Allocable	2.02	147	1,951	229	0	0	736
8.06	Transmission	5.07	25	385	10	0	0	3,506
8.07	Distribution	6.16	91	682	200	1,978	1,195	114
8.08	Total Ptd Wages & Salaries	SUM	426	5,430	572	1,978	1,195	9,190
8.09	Wtd Ptd Wage & Sal Ratios		0.30%	3.80%	0.40%	1.38%	0.84%	6.43%
8.10	Customer Accounting	7.06	2	31	152	0	0	86
8.11	Customer Serv & Info. Sales	4.02	0	0	27	0	0	0
8.12	Eccr	4.02	0	1	47	0	0	0
8.13	Total PTDCSS Wages & Salaries	SUM	428	5,462	797	1,978	1,195	9,276
8.14	Wtd PTDCSS Wage & Sal Ratios		0.26%	3.27%	0.48%	1.18%	0.71%	5.55%
8.15	Administrative & General	8.14	21	273	40	99	60	463
8.16	Total Wages And Salaries Exp	SUM	449	5,735	837	2,076	1,254	9,740
8.17	Wtd Wage And Salary Ratios		0.26%	3.27%	0.48%	1.18%	0.71%	5.55%
8.18	Retail Only Wage and Salary Ratios		0.27%	3.46%	0.51%	1.25%	0.76%	0.00%
9.01	Present Class Revenues	DA	4,114	44,335	5,283	21,929	10,299	111,762
9.02	Present Revenue Ratios		0.27%	2.94%	0.35%	1.45%	0.68%	7.41%
9.03	Retail only Ratios		0.29%	3.17%	0.38%	1.57%	0.74%	
10.01	Direct Assignment Wholesale		0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Gross Electric Plant In Service							
	Production Plant							
16.01	Base	1.02	2,488,732	2,388,113	1,418,730	70,545	3,606	769,426
16.02	Intermediate	1.04	437,381	378,658	224,953	11,186	572	122,000
16.03	Peaking	1.06	530,639	395,655	235,051	11,688	597	127,476
16.04	Direct Wholesale	DA	5,508	0	0	0	0	0
16.05	Production Plant In Service	SUM	3,462,260	3,162,426	1,878,734	93,418	4,775	1,018,902
16.06	Ratio		100.00%	91.34%	54.26%	2.70%	0.14%	29.43%
	Transmission Plant							
17.01	Gen. Step-Up - Base	1.02	16,063	15,414	9,157	455	23	4,966
17.02	Gen. Step-Up - Intermediate	1.04	3,182	2,755	1,637	81	4	888
17.03	Gen. Step-Up - Peaking	1.06	15,622	11,648	6,920	344	18	3,753
17.04	Transmission	1.08	925,774	667,622	416,649	19,234	888	200,921
17.05	Transmission Plant In Service	SUM	960,641	697,438	434,363	20,115	933	210,527
17.06	Ratio		100.00%	72.60%	45.22%	2.09%	0.10%	21.92%
17.07	Total Prod & Trans Plant	SUM	4,422,901	3,859,864	2,313,097	113,533	5,708	1,229,429
17.08	Ratio		100.00%	87.27%	52.30%	2.57%	0.13%	27.80%
	Distribution Plant							
18.01	Primary	3.02	1,171,725	1,166,206	743,491	41,925	1,143	326,981
18.02	Secondary	3.04	807,905	807,905	623,299	42,900	485	136,358
18.03	Services	3.06	327,389	327,389	290,672	23,644	2,331	10,660
18.04	Meters	3.08	138,081	136,512	108,025	9,792	748	17,095
18.05	Lighting Fixtures	3.10	122,903	122,903	0	0	0	0
18.06	Lighting Poles	3.12	74,247	74,247	0	0	0	0
18.07	Is Equipment	3.14	1,958	1,958	0	0	0	0
18.08	Distribution Plant In Service	SUM	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
18.09	Ratio		100.00%	99.73%	66.77%	4.47%	0.18%	18.57%
19.01	Total Trans & Dist Plant	SUM	3,604,849	3,334,559	2,199,850	138,376	5,640	701,622
19.02	Total Gross Ptd Plant	SUM	7,067,109	6,496,985	4,078,584	231,794	10,415	1,720,524
19.03	Ratio		100.00%	91.93%	57.71%	3.28%	0.15%	24.35%
20.01	General & Intangible Plant							
20.02	Labor Related	8.17	340,041	321,164	206,192	12,975	808	81,124
20.03	Retail Customer Related (Css)	4.02	57,976	57,976	51,094	4,140	410	1,877
20.04	General Plant In Service	SUM	398,017	379,140	257,286	17,116	1,218	83,001
20.05	Gross Electric Plant In Service	SUM	7,465,126	6,876,125	4,335,870	248,910	11,633	1,803,525
20.06	GP Ratio		100.00%	92.11%	58.08%	3.33%	0.16%	24.16%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Gross Electric Plant In Service							
	Production Plant							
16.01	Base	1.02	7,594	112,026	6,185	0	0	100,619
16.02	Intermediate	1.04	1,204	17,763	981	0	0	58,723
16.03	Peaking	1.06	1,258	18,560	1,025	0	0	134,984
16.04	Direct Wholesale	DA	0	0	0	0	0	5,508
16.05	Production Plant In Service	SUM	10,057	148,349	8,191	0	0	299,834
16.06	Ratio		0.29%	4.28%	0.24%	0.00%	0.00%	8.66%
	Transmission Plant							
17.01	Gen. Step-Up - Base	1.02	49	723	40	0	0	649
17.02	Gen. Step-Up - Intermediate	1.04	9	129	7	0	0	427
17.03	Gen. Step-Up - Peaking	1.06	37	546	30	0	0	3,974
17.04	Transmission	1.08	1,749	27,539	641	0	0	258,152
17.05	Transmission Plant In Service	SUM	1,844	28,938	718	0	0	263,203
17.06	Ratio		0.19%	3.01%	0.07%	0.00%	0.00%	27.40%
17.07	Total Prod & Trans Plant	SUM	11,900	177,287	8,909	0	0	563,037
17.08	Ratio		0.27%	4.01%	0.20%	0.00%	0.00%	12.73%
	Distribution Plant							
18.01	Primary	3.02	5,598	38,426	8,642	0	0	5,519
18.02	Secondary	3.04	8	1,188	3,668	0	0	0
18.03	Services	3.06	0	10	72	0	0	0
18.04	Meters	3.08	30	775	46	0	0	1,569
18.05	Lighting Fixtures	3.10	0	0	0	122,903	0	0
18.06	Lighting Poles	3.12	0	0	0	0	74,247	0
18.07	Is Equipment	3.14	0	1,958	0	0	0	0
18.08	Distribution Plant In Service	SUM	5,636	42,357	12,428	122,903	74,247	7,087
18.09	Ratio		0.21%	1.60%	0.47%	4.65%	2.81%	0.27%
19.01	Total Trans & Dist Plant	SUM	7,480	71,295	13,146	122,903	74,247	270,290
19.02	Total Gross Ptd Plant	SUM	17,536	219,645	21,337	122,903	74,247	570,124
19.03	Ratio		0.25%	3.11%	0.30%	1.74%	1.05%	8.07%
20.01	General & Intangible Plant							
20.02	Labor Related	8.17	871	11,115	1,622	4,024	2,431	18,877
20.03	Retail Customer Related (Css)	4.02	0	6	449	0	0	0
20.04	General Plant In Service	SUM	871	11,121	2,071	4,024	2,431	18,877
20.05	Gross Electric Plant In Service	SUM	18,408	230,766	23,408	126,927	76,678	589,001
20.06	GP Ratio		0.25%	3.09%	0.31%	1.70%	1.03%	7.89%

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Depreciation							
	Production Plant							
21.01	Base	1.02	1,423,300	1,365,756	811,368	40,344	2,062	440,033
21.02	Intermediate	1.04	383,807	332,277	197,399	9,815	502	107,056
21.03	Peaking	1.06	239,473	178,556	106,076	5,275	270	57,529
21.04	DA Wholesale	10.01	9,312	0	0	0	0	0
21.05	Adj G - Unfunded Nuc Deconunissioning W/S	10.01	-2,286	0	0	0	0	0
21.06	Total Prod Deprec Reserve	SUM	2,053,606	1,876,589	1,114,844	55,434	2,834	604,618
	Transmission Plant							
22.01	Gen. Step-Up - Base	1.02	5,394	5,176	3,075	153	8	1,668
22.02	Gen. Step-Up - Intermediate	1.04	1,069	925	550	27	1	298
22.03	Gen. Step-Up - Peaking	1.06	5,246	3,912	2,324	116	6	1,260
22.04	Transmission	1.08	426,327	307,446	191,871	8,858	409	92,526
22.05	Total Trans Deprec Reserve	SUM	438,036	317,459	197,819	9,153	424	95,752
	Distribution Plant							
23.01	Primary	3.02	428,837	426,817	272,109	15,344	418	119,671
23.02	Secondary	3.04	335,976	335,976	259,205	17,840	202	56,706
23.03	Services	3.06	120,990	120,990	107,421	8,738	861	3,939
23.04	Meters	3.08	54,864	54,241	42,922	3,891	297	6,793
23.05	Lighting Fixtures	3.10	65,524	65,524	0	0	0	0
23.06	Lighting Poles	3.12	36,587	36,587	0	0	0	0
23.07	Is Equipment	3.14	918	918	0	0	0	0
23.08	Total Dist Deprec Reserve	SUM	1,043,696	1,041,053	681,657	45,813	1,779	187,109
	General & Intangible							
24.01		8.17	140,726	132,914	85,333	5,370	334	33,573
24.02	(Css)	4.02	41,781	41,781	36,821	2,984	295	1,353
24.03	Total General Deprec Reserve	SUM	182,507	174,695	122,154	8,354	630	34,926
	Common & Other Plant							
25.01	Progress	20.06	4,942	4,552	2,870	165	8	1,194
25.01	Total Com & Other Plant	SUM	4,942	4,552	2,870	165	8	1,194
25.02	Total Accumulated Depreciation	SUM	3,722,787	3,414,347	2,119,344	118,919	5,674	923,599

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Depreciation							
	Production Plant							
21.01	Base	1.02	4,343	64,068	3,537	0	0	57,544
21.02	Intermediate	1.04	1,057	15,587	861	0	0	51,530
21.03	Peaking	1.06	568	8,376	462	0	0	60,917
21.04	DA Wholesale	10.01	0	0	0	0	0	9,312
21.05	Adj G - Unfunded Nuc Decommissioning W/S	10.01	0	0	0	0	0	-2,286
21.06	Total Prod Deprec Reserve	SUM	5,968	88,031	4,860	0	0	177,017
	Transmission Plant							
22.01	Gen. Step-Up - Base	1.02	16	243	13	0	0	218
22.02	Gen. Step-Up - Intermediate	1.04	3	43	2	0	0	144
22.03	Gen. Step-Up - Peaking	1.06	12	183	10	0	0	1,334
22.04	Transmission	1.08	806	12,682	295	0	0	118,881
22.05	Total Trans Deprec Reserve	SUM	837	13,152	321	0	0	120,577
	Distribution Plant							
23.01	Primary	3.02	2,049	14,064	3,163	0	0	2,020
23.02	Secondary	3.04	3	494	1,525	0	0	0
23.03	Services	3.06	0	4	27	0	0	0
23.04	Meters	3.08	12	308	18	0	0	623
23.05	Lighting Fixtures	3.10	0	0	0	65,524	0	0
23.06	Lighting Poles	3.12	0	0	0	0	36,587	0
23.07	I: Equipment	3.14	0	918	0	0	0	0
23.08	Total Dist Deprec Reserve	SUM	2,064	15,787	4,733	65,524	36,587	2,643
	General & Intangible Plant							
24.01	La Related	8.17	360	4,600	671	1,666	1,006	7,812
24.02	(Css)	4.02	0	4	323	0	0	0
24.03	Total General Deprec Reserve	SUM	361	4,604	995	1,666	1,006	7,812
	Common & Other Plant							
25.01	Retirement Work In Progress	20.06	12	153	15	84	51	390
25.01	Total Com & Other Plant	SUM	12	153	15	84	51	390
25.02	Total Accumulated Depreciation	SUM	9,242	121,727	10,925	67,274	37,644	308,440

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Net Electric Plant							
	Production Plant							
26.01	Productio t In Service	PULL	3,462,260	3,162,426	1,878,734	93,418	4,775	1,018,902
26.02	Deprec	PULL	-2,053,606	-1,876,589	-1,114,844	-55,434	-2,834	-604,618
26.03	Net Production Plant	SUM	1,408,654	1,285,837	763,890	37,984	1,942	414,284
	Transmission Plant							
27.01	Tran Plant In Service	PULL	960,641	697,438	434,363	20,115	933	210,527
27.02	Deprec	PULL	-438,036	-317,459	-197,819	-9,153	-424	-95,752
27.03	Net Transmission Plant	SUM	522,605	379,980	236,544	10,962	509	114,776
	Distribution Plant							
28.01	Distribution Plant In Service	PULL	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
28.02	Deprec	PULL	-1,043,696	-1,041,053	-681,657	-45,813	-1,779	-187,109
28.03	Net Distribution Plant	SUM	1,600,512	1,596,068	1,083,830	72,448	2,928	303,985
29.01	Net Ptd Plant	SUM	3,531,771	3,261,884	2,084,264	121,393	5,379	833,045
29.02	Net Trans & Dist Plant	SUM	2,123,117	1,976,047	1,320,374	83,410	3,437	418,761
	General & Intangible Plant							
30.01	General Plant In Ser	PULL	398,017	379,140	257,286	17,116	1,218	83,001
30.02	Deprec	PULL	-182,507	-174,695	-122,154	-8,354	-630	-34,926
30.03	Net General & Intang Plant	SUM	215,510	204,445	135,132	8,762	588	48,075
	Common & Other Plant							
31.01	Total Com & er Plant	PULL	-4,942	-4,552	-2,870	-165	-8	-1,194
31.01	Net Common & Other Plant	SUM	-4,942	-4,552	-2,870	-165	-8	-1,194
31.02	Net Electric Plant In Service	SUM	3,742,339	3,461,777	2,216,526	129,991	5,959	879,926

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Net Electric Plant							
	Production Plant							
26.01	Production Plant In Service	PULL	10,057	148,349	8,191	0	0	299,834
26.02	Total Prod Deprec Reserv	PULL	-5,968	-88,031	-4,860	0	0	-177,017
26.03	Net Production Plant	SUM	4,089	60,319	3,330	0	0	122,817
	Transmission Plant							
27.01	Transmission Plant In Service	PULL	1,844	28,938	718	0	0	263,203
27.02	Total Trans Deprec Reserve	PULL	-837	-13,152	-321	0	0	-120,577
27.03	Net Transmission Plant	SUM	1,007	15,786	397	0	0	142,625
	Distribution Plant							
28.01	Distribution Plant In Service	PULL	5,636	42,357	12,428	122,903	74,247	7,087
28.02	Total Dist Deprec Reserve	PULL	-2,064	-15,787	-4,733	-65,524	-36,587	-2,643
28.03	Net Distribution Plant	SUM	3,572	26,570	7,695	57,379	37,660	4,444
29.01	Net Ptd Plant	SUM	8,667	102,675	11,422	57,379	37,660	269,887
29.02	Net Trans & Dist Plant	SUM	4,579	42,356	8,092	57,379	37,660	147,070
	General & Intangible Plant							
30.01	General Plant In Ser	PULL	871	11,121	2,071	4,024	2,431	18,877
30.02	Deprec	PULL	-361	-4,604	-995	-1,666	-1,006	-7,812
30.03	Net General & Intang Plant	SUM	511	6,517	1,076	2,359	1,425	11,065
	Common & Other Plant							
31.01	Total Com & Other Plant	PULL	-12	-153	-15	-84	-51	-390
31.01	Net Common & Other Plant	SUM	-12	-153	-15	-84	-51	-390
31.02	Net Electric Plant In Service	SUM	9,166	109,039	12,483	59,654	39,034	280,562

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	O & M Expenses							
	Production O & M							
	Energy Related Prod O & M							
32.01	Non-Recoverable Fuel-Allocable	2.02	8,390	8,192	4,130	260	17	3,161
32.02	Direct Wholesale	10.01	5,476	0	0	0	0	0
32.03	Non-Fuel O&M - Allocable	2.02	74,521	72,767	36,683	2,309	151	28,075
32.04	Adj E - Last Core Nuclear Fuel	2.02	1,200	1,172	591	37	2	452
32.05	Total Energy Related	SUM	89,587	82,131	41,404	2,606	171	31,688
	Demand Related Prod O & M							
33.01	Base	1.02	97,408	93,470	55,529	2,761	141	30,115
33.02	Intermediate	1.04	15,756	13,641	8,104	403	21	4,395
33.03	Peaking	1.06	19,285	14,379	8,542	425	22	4,633
33.04	Direct Wholesale	10.01	12,388	0	0	0	0	0
33.05	Purchase Power-D.A. Retail	4.02	4,412	4,412	3,888	315	31	143
33.06	Adj F-Nuclear M&S Inventory	1.02	1,667	1,600	950	47	2	515
33.07	Total Demand Related	SUM	150,916	127,501	77,013	3,951	217	39,801
33.07	Total Production O & M	SUM	240,503	209,632	118,417	6,557	388	71,489
	Transmission O & M							
34.01	Gen. Step-Up - Base	1.02	578	555	329	16	1	179
34.02	Gen. Step-Up - Intermediate	1.04	114	99	59	3	0	32
34.03	Gen. Step-Up - Peaking	1.06	562	419	249	12	1	135
34.04	Transmission	1.08	33,032	23,821	14,866	686	32	7,169
34.05	Total Transmission O & M	SUM	34,286	24,893	15,503	718	33	7,514
	Distribution O & M							
35.01	Primary	3.02	46,821	46,600	29,709	1,675	46	13,066
35.02	Secondary	3.04	21,341	21,341	16,465	1,133	13	3,602
35.03	Services Incl R/D	3.06	18,144	18,144	16,109	1,310	129	591
35.04	Meters	3.08	4,024	3,978	3,148	285	22	498
35.05	Lighting Fixtures	3.10	4,174	4,174	0	0	0	0
35.06	Lighting Poles	3.12	2,573	2,573	0	0	0	0
35.07	Is Equipment	3.14	95	95	0	0	0	0
35.08	Total Distribution O & M	SUM	97,172	96,906	65,431	4,404	209	17,757

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Expenses							
	Production O & M							
	Energy Related Prod O & M							
32.01	Non-Recoverable Fuel-Allocable	2.02	40	524	62	0	0	198
32.02	Direct Wholesale	10.01	0	0	0	0	0	5,476
32.03	Non-Fuel O&M - Allocable	2.02	351	4,651	546	0	0	1,754
32.04	Adj E - Last Core Nuclear Fuel	2.02	6	75	9	0	0	28
32.05	Total Energy Related	SUM	397	5,249	617	0	0	7,456
	Demand Related Prod O & M							
33.01	Base	1.02	297	4,385	242	0	0	3,938
33.02	Intermediate	1.04	43	640	35	0	0	2,115
33.03	Peaking	1.06	46	675	37	0	0	4,906
33.04	Direct Wholesale	10.01	0	0	0	0	0	12,388
33.05	Purchase Power-D.A. Retail	4.02	0	0	34	0	0	0
33.06	Adj E-Nuclear M&S Inventory	1.02	5	75	4	0	0	67
33.07	Total Demand Related	SUM	391	5,775	353	0	0	23,415
33.07	Total Production O & M	SUM	788	11,024	970	0	0	30,871
	Transmission O & M							
34.01	Gen. Step-Up - Base	1.02	2	26	1	0	0	23
34.02	Gen. Step-Up - Intermediate	1.04	0	5	0	0	0	15
34.03	Gen. Step-Up - Peaking	1.06	1	20	1	0	0	143
34.04	Transmission	1.08	62	983	23	0	0	9,211
34.05	Total Transmission O & M	SUM	66	1,033	26	0	0	9,393
	Distribution O & M							
35.01	Primary	3.02	224	1,535	345	0	0	221
35.02	Secondary	3.04	0	31	97	0	0	0
35.03	Services Incl R/D	3.06	0	1	4	0	0	0
35.04	Meters	3.08	1	23	1	0	0	46
35.05	Lighting Fixtures	3.10	0	0	0	4,174	0	0
35.06	Lighting Poles	3.12	0	0	0	0	2,573	0
35.07	Is Equipment	3.14	0	95	0	0	0	0
35.08	Total Distribution O & M	SUM	225	1,685	448	4,174	2,573	266

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Customer Accounting							
36.01	Meter Reading	4.04	10,910	10,807	9,395	762	66	468
36.02	Customer Records	4.06	42,806	42,806	37,724	3,057	303	1,386
36.03	Billing	4.08	6,416	6,212	5,276	429	42	210
36.04	Service Work For Conp	3.06	1,703	1,703	1,512	123	12	55
36.05	Uncollectibles	9.03	4,165	4,165	2,644	184	8	1,073
36.06	Total Customer Accounting Exp	SUM	66,000	65,693	56,551	4,555	431	3,192
37.01	Customer Service & Information	4.02	5,041	5,041	4,443	360	36	163
38.01	Sales	4.02	6,426	6,426	5,663	459	45	208
38.02	Economic Development Adjustment	4.02	-20	-20	-18	-1	0	-1
38.03	Total Sales	SUM	6,406	6,406	5,646	457	45	207
	Administrative & General Expenses							
39.01	Production-Base	1.02	-2,830	-2,716	-1,613	-80	-4	-875
39.02	Transmission	1.08	600	433	270	12	1	130
39.03	Distribution	18.09	5,400	5,386	3,605	242	10	1,003
39.04	Gross Plant Related	20.06	3,920	3,611	2,277	131	6	947
39.05	Labor Related	8.17	38,679	36,532	23,454	1,476	92	9,228
39.06	DA Wholesale	10.01	392	0	0	0	0	0
39.07	Retail Labor	8.18	292	292	187	12	1	74
39.08	Rate Case Expense Adjustment	9.03	822	822	522	36	1	212
39.09	Adj to Advertising	8.17	-4,007	-3,785	-2,430	-153	-10	-956
39.10	Adj to Industry Association Dues	8.17	-3	-3	-2	0	0	-1
39.11	Adj for Interest Tax Deficiency	20.06	-1,574	-1,450	-914	-52	-2	-380
39.12	Acquisition Adjustment	8.17	58,700	55,441	35,594	2,240	139	14,004
39.13	Total Administrative and General	SUM	100,391	94,563	60,951	3,863	234	23,386
40.01	Total O&M Expenses	SUM	549,799	503,134	326,941	20,915	1,376	123,709
40.02	Ratio		100.00%	91.51%	59.47%	3.80%	0.25%	22.50%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	[redacted]	Alloc.	e	Int	ergy		Lighting Poles	
	Customer Accounting							
36.01	Meter Reading	4.04	6	108	2	0	0	103
36.02	Customer Records	4.06	0	4	331	0	0	0
36.03	Billing	4.08	1	14	240	0	0	204
36.04	Service Work For Conp	3.06	0	0	0	0	0	0
36.05	Uncollectibles	9.03	12	132	16	65	31	0
36.06	Total Customer Accounting Exp	SUM	19	259	590	65	31	307
37.01	Customer Service & Information	4.02	0	1	39	0	0	0
38.01	Sales	4.02	0	1	50	0	0	0
38.02	Economic Development Adjustment	4.02	0	0	0	0	0	0
38.03	Total Sales	SUM	0	1	50	0	0	0
	Administrative & General Expenses							
39.01	Production-Base	1.02	-9	-127	-7	0	0	-114
39.02	Transmission	1.08	1	18	0	0	0	167
39.03	Distribution	18.09	12	87	25	251	152	14
39.04	Gross Plant Related	20.06	10	121	12	67	40	309
39.05	Labor Related	8.17	99	1,264	185	458	277	2,147
39.06	DA Wholesale	10.01	0	0	0	0	0	392
39.07	Retail Labor	8.18	1	10	1	4	2	0
39.08	Rate Case Expense Adjustment	9.03	2	26	3	13	6	0
39.09	Adj to Advertising	8.17	-10	-131	-19	-47	-29	-222
39.10	Adj to Industry Association Dues	8.17	0	0	0	0	0	0
39.11	Adj for Interest Tax Deficiency	20.06	-4	-49	-5	-27	-16	-124
39.12	Acquisition Adjustment	8.17	150	1,919	280	695	420	3,259
39.13	Total Administrative and General	SUM	252	3,138	476	1,412	852	5,828
40.01	Total O&M Expenses	SUM	1,350	17,139	2,597	5,652	3,455	46,665
40.02	Ratio		0.25%	3.12%	0.47%	1.03%	0.63%	8.49%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Rate Base Adjustments							
	Additive Adjustments							
	Plant Held For Future Use							
41.01	Transmission	1.08	6,602	4,761	2,971	137	6	1,433
41.02	Distribution	3.02	1,673	1,665	1,062	60	2	467
41.03	Total Land Held For Future Use	SUM	8,275	6,426	4,033	197	8	1,900
	Construction Work Progress							
42.01	Production	16.06	100,598	91,886	54,588	2,714	139	29,605
42.02	Transmission	1.08	25,236	18,199	11,358	524	24	5,477
42.03	Distribution	18.09	17,907	17,859	11,956	801	32	3,326
42.04	General	8.17	5,731	5,413	3,475	219	14	1,367
42.05	Adj C - Remove Afud Cwip Prod	16.06	-66,597	-60,830	-36,138	-1,797	-92	-19,599
42.06	Total Rate Base Cwip	SUM	82,875	72,527	45,239	2,461	117	20,176
43.01	Total Additive Adjustments	SUM	91,150	78,953	49,272	2,658	125	22,076
43.02	Net Original Cost Rate Base	SUM	3,833,489	3,540,731	2,265,797	132,649	6,084	902,002
	Working Capital							
	Materials And Supplies							
	Fuel Supplies							
44.01	Amount Allocable	2.08	139,178	126,090	63,564	4,001	262	48,648
44.02	DA Wholesale Tallahassee	10.01	780	0	0	0	0	0
44.03	Adj	2.02	-369	-360	-182	-11	-1	-139
44.04	Total Fuel Stocks	SUM	139,589	125,730	63,383	3,989	262	48,509
	Plant Materials & Supplies							
45.01	Amount Allocable	20.06	91,721	84,484	53,273	3,058	143	22,159
45.02	DA Wholesale Tallahassee	10.01	394	0	0	0	0	0
45.03	Adj F-Nuclear M&S Inventory	20.06	-512	-472	-297	-17	-1	-124
45.04	Total Plant Materials & Suppl	SUM	91,603	84,013	52,976	3,041	142	22,035
41.04	Total Materials & Supplies	SUM	231,192	209,742	116,358	7,031	404	70,544
46.01	Prepayments	19.03	219,710	201,985	126,799	7,206	324	53,490
	Miscellaneous Working Capital							
47.01	OPEB - D.A. Retail	8.18	-136,685	-136,685	-87,754	-5,522	-344	-34,526
47.02	OPEB - DA Wholeale	10.01	678	0	0	0	0	0
47.03	D.A. Retail-Doe D&D Nuclear	1.10	9,922	9,922	5,894	293	15	3,197
47.04	Misc Other	40.02	-180,952	-165,594	-107,604	-6,884	-453	-40,715
47.05	Adj B - Gain/Loss Property	20.06	-2,865	-2,639	-1,664	-96	-4	-692
47.06	Adj J - Retail Rate Case Exp	9.03	-252	-252	-160	-11	0	-65
47.07	Adj K - Section 1341	20.06	8,995	8,285	5,224	300	14	2,173
47.08	Total Misc Work Capital	SUM	-301,159	-286,962	-186,063	-11,919	-773	-70,628
48.01	Total Working Capital	SUM	149,743	124,765	57,095	2,317	-45	53,406
	Preliminary Summary							
49.01	Total ments		91,150	78,953	49,272	2,658	125	22,076
49.02	Total Working Capital		149,743	124,765	57,095	2,317	-45	53,406
49.03	Total Rate Base Adjustments		240,893	203,719	106,367	4,976	79	75,481
	Rate Base Calculation							
49.04	Net Electric Plan Service		3,742,339	3,461,777	2,216,526	129,991	5,959	879,926
49.05	Total Rate Base Adjustments		240,893	203,719	106,367	4,976	79	75,481
49.06	Total Rate Base		3,983,232	3,665,496	2,322,892	134,966	6,038	955,407
49.07	Ratio		100.00%	92.02%	58.32%	3.39%	0.15%	23.99%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Rate Base Adjustments							
	Additive Adjustments							
	Plant Held For Future Use							
41.01	Transmission	1.08	12	196	5	0	0	1,841
41.02	Distribution	3.02	8	55	12	0	0	8
41.03	Total Land Held For Future Use	SUM	20	251	17	0	0	1,849
	Construction Work In Progress							
42.01	Production	16.06	292	4,310	238	0	0	8,712
42.02	Transmission	1.08	48	751	17	0	0	7,037
42.03	Distribution	18.09	38	287	84	832	503	48
42.04	General	8.17	15	187	27	68	41	318
42.05	Adj C - Remove Afud Cwip Prod	16.06	-193	-2,854	-158	0	0	-5,767
42.06	Total Rate Base Cwip	SUM	199	2,682	209	900	544	10,348
43.01	Total Additive Adjustments	SUM	220	2,933	226	900	544	12,197
43.02	Net Original Cost Rate Base	SUM	9,386	111,972	12,709	60,554	39,578	292,758
	Working Capital							
	Materials And Supplies							
	Fuel Supplies							
44.01	Amount Allocable	2.08	609	8,058	947	0	0	13,088
44.02	DA Wholesale Tallahassee	10.01	0	0	0	0	0	780
44.03	Adj E-Last Core Nuclear Fuel	2.02	-2	-23	-3	0	0	-9
44.04	Total Fuel Stocks	SUM	607	8,035	944	0	0	13,859
	Plant Materials & Supplies							
45.01	Amount Allocable	20.06	226	2,835	288	1,560	942	7,237
45.02	DA Wholesale Tallahassee	10.01	0	0	0	0	0	394
45.03	Adj F-Nuclear M&S Inventory	20.06	-1	-16	-2	-9	-5	-40
45.04	Total Plant Materials & Suppl	SUM	225	2,820	286	1,551	937	7,590
41.04	Total Materials & Supplies	SUM	832	10,855	1,230	1,551	937	21,450
46.01	Prepayments	19.03	545	6,829	663	3,821	2,308	17,725
	Miscellaneous Working Capital							
47.01	OPEB - D.A. Retail	8.18	-371	-4,731	-690	-1,713	-1,035	0
47.02	OPEB - DA Wholeale	10.01	0	0	0	0	0	678
47.03	D.A. Retail-Doe D&D Nuclear	1.10	32	465	26	0	0	0
47.04	Misc Other	40.02	-444	-5,641	-855	-1,860	-1,137	-15,358
47.05	Adj B - Gain/Loss Property	20.06	-7	-89	-9	-49	-29	-226
47.06	Adj J - Retail Rate Case Exp	9.03	-1	-8	-1	-4	-2	0
47.07	Adj K - Section 1341	20.06	22	278	28	153	92	710
47.08	Total Misc Work Capital	SUM	-769	-9,724	-1,501	-3,473	-2,111	-14,197
48.01	Total Working Capital	SUM	608	7,959	392	1,899	1,134	24,978
	Preliminary Summary							
49.01	Total Additive Adjustments		220	2,933	226	900	544	12,197
49.02	Total Working Capital		608	7,959	392	1,899	1,134	24,978
49.03	Total Rate Base Adjustments		828	10,892	618	2,799	1,678	37,174
	Rate Base Calculation							
49.04	Net Electric Plant In Service		9,166	109,039	12,483	59,654	39,034	280,562
49.05	Total Rate Base Adjustments		828	10,892	618	2,799	1,678	37,174
49.06	Total Rate Base		9,994	119,931	13,102	62,453	40,712	317,736
49.07	Ratio		0.25%	3.01%	0.33%	1.57%	1.02%	7.98%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
51.01	Present Class Revenues	DA	1,509,008	1,397,246	886,989	61,766	2,542	359,989
	Revenue Credits							
52.01	Production Demand Related	16.06	2,325	2,124	1,262	63	3	684
52.02	Transmission Related	1.08	1,118	806	503	23	1	243
52.03	Distribution Plant Related	3.02	6,773	6,741	4,298	242	7	1,890
52.04	Gross Plant Related	20.06	1,812	1,669	1,052	60	3	438
52.05	Rate Base Related	49.07	8,160	7,509	4,759	276	12	1,957
52.06	Energy Non-Fuel Related	2.04	2,424	2,280	1,149	72	5	880
52.07	Distribution Services	3.06	9,560	9,560	8,488	690	68	311
52.08	Distribution Secondary	3.04	6,720	6,720	5,184	357	4	1,134
52.09	Customer Accounting	4.06	147	147	130	10	1	5
52.10	Total Revenue Credits	SUM	39,039	37,556	26,825	1,795	104	7,542
53.01	Total Present Revenues	SUM	1,548,047	1,434,802	913,814	63,561	2,646	367,531

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
51.01	Present Class Revenues	DA	4,114	44,335	5,283	21,929	10,299	111,762
	Revenue Credits							
52.01	Production Demand Related	16.06	7	100	6	0	0	201
52.02	Transmission Related	1.08	2	33	1	0	0	312
52.03	Distribution Plant Related	3.02	32	222	50	0	0	32
52.04	Gross Plant Related	20.06	4	56	6	31	19	143
52.05	Rate Base Related	49.07	20	246	27	128	83	651
52.06	Energy Non-Fuel Related	2.04	11	146	17	0	0	144
52.07	Distribution Services	3.06	0	0	2	0	0	0
52.08	Distribution Secondary	3.04	0	10	31	0	0	0
52.09	Accounting	4.06	0	0	1	0	0	0
52.10	Total Revenue Credits	SUM	77	813	140	159	102	1,483
53.01	Total Present Revenues	SUM	4,191	45,148	5,423	22,088	10,401	113,245

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Depreciation Expense							
	Production Depreciation							
54.01	Base	1.02	115,509	110,839	65,847	3,274	167	35,711
54.02	Intermediate	1.04	23,365	20,228	12,017	598	31	6,517
54.03	Peaking	1.06	22,922	17,091	10,153	505	26	5,507
54.04	DA Wholesale	10.1	538	0	0	0	0	0
54.05	D.A. Retail	1.10	8,733	8,733	5,188	258	13	2,814
54.06	Adj L - Accel Amort Tiger Bay	1.10	9,000	9,000	5,347	266	14	2,900
54.07	Total Production Dep ec Exp		180,067	165,891	98,553	4,900	250	53,448
	Transmission Depreciation							
55.01	Gen. Step-Up - Base	1.02	477	458	272	14	1	147
55.02	Gen. Step-Up - Intermediate	1.04	94	81	48	2	0	26
55.03	Gen. Step-Up - Peaking	1.06	464	346	206	10	1	111
55.04	T ansmission	1.08	28,831	20,791	12,976	599	28	6,257
55.05	Total Trans Deprec Exp	SUM	29,866	21,677	13,501	625	29	6,542
	Distribution Depreciation							
56.01	Primary	3.02	40,494	40,303	25,695	1,449	39	11,300
56.02	Secondary	3.04	34,997	34,997	27,000	1,858	21	5,907
56.03	Services	3.06	12,284	12,284	10,906	887	87	400
56.04	Meters	3.08	5,134	5,076	4,016	364	28	636
56.05	Lighting Fixtures	3.1	10,166	10,166	0	0	0	0
56.06	Lighting Poles	3.12	4,386	4,386	0	0	0	0
56.07	Is Equipment	3.14	90	90	0	0	0	0
56.08	Total Dist Dep ec Expense	SUM	107,551	107,302	67,618	4,558	176	18,243
	General & Intang Depreciation							
57.01	Labor Related	8.17	26,550	25,076	16,099	1,013	63	6,334
57.02	Retail Customer Related (Css)	4.02	5,798	5,798	5,110	414	41	188
57.03	Adj S - Sebring	8.17	-2,208	-2,085	-1,339	-84	-5	-527
57.04	Total General Deprec Expense	SUM	30,140	28,789	19,870	1,343	99	5,995
58.01	Total Depreciation Expense	SUM	347,624	323,658	199,542	11,427	554	84,228

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Depreciation Expense							
	Production Depreciation							
54.01	Base	1.02	352	5,199	287	0	0	4,670
54.02	Intermediate	1.04	64	949	52	0	0	3,137
54.03	Peaking	1.06	54	802	44	0	0	5,831
54.04	DA Wholesale	10.1	0	0	0	0	0	538
54.05	D.A. Retail	1.10	28	410	23	0	0	0
54.06	Adj L - Accel Amort Tiger Bay	1.10	29	422	23	0	0	0
54.07	Total Production Deprec Exp		528	7,782	430	0	0	14,176
	Transmission Depreciation							
55.01	Gen. Step-Up - Base	1.02	1	21	1	0	0	19
55.02	Gen. Step-Up - Intermediate	1.04	0	4	0	0	0	13
55.03	Gen. Step-Up - Peaking	1.06	1	16	1	0	0	118
55.04	Transmission	1.08	54	858	20	0	0	8,040
55.05	Total Trans Deprec Exp	SUM	57	899	22	0	0	8,189
	Distribution Depreciation							
56.01	Primary	3.02	193	1,328	299	0	0	191
56.02	Secondary	3.04	0	51	159	0	0	0
56.03	Services	3.06	0	0	3	0	0	0
56.04	Meters	3.08	1	29	2	0	0	58
56.05	Lighting Fixtures	3.1	0	0	0	10,166	0	0
56.06	Lighting Poles	3.12	0	0	0	0	4,386	0
56.07	Equipment	3.14	0	90	0	0	0	0
56.08	Total Dist Deprec Expense	SUM	195	1,499	462	10,166	4,386	249
	General & Intang Depreciation							
57.01	Labor Related	8.17	68	868	127	314	190	1,474
57.02	Retail Customer Related (Css)	4.02	0	1	45	0	0	0
57.03	Adj Sebring	8.17	-6	-72	-11	-26	-16	-123
57.04	Total General Deprec Expense	SUM	62	796	161	288	174	1,351
58.01	Total Depreciation Expense	SUM	842	10,976	1,075	10,454	4,560	23,965

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Taxes Other Than Inc & Rev							
	Real Estate & Property Tax							
59.01	Amount Allocable	20.06	85,272	78,544	49,527	2,843	133	20,601
59.02	DA Wholesale	10.10	102	0	0	0	0	0
59.03	Total Real Est & Prop Tax	SUM	85,374	78,544	49,527	2,843	133	20,601
60.01	Payroll Tax	8.17	14,159	13,373	8,586	540	34	3,378
61.01	Total Other Tax & Misc. Expense	SUM	99,533	91,917	58,113	3,384	167	23,979
	Other Taxes & Misc Expenses							
62.01	Revenue Taxes	9.03	139,119	139,119	88,314	6,150	253	35,843
62.02	Adj B - Gain/Loss Property	20.06	-1,891	-1,742	-1,098	-63	-3	-457
62.03	Adj	9.03	-138,166	-138,166	-87,709	-6,108	-251	-35,597
62.04	Misc Allowable Expenses	SUM		-789	-493	-21	-1	-211

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Taxes Other Than Inc & Rev							
	Real Estate & Property Tax							
59.01	Amount Allocable	20.06	210	2,636	267	1,450	876	6,728
59.02	DA Wholesale	10.10	0	0	0	0	0	102
59.03	Total Real Est & Prop Tax	SUM	210	2,636	267	1,450	876	6,830
60.01	Payroll Tax	8.17	36	463	68	168	101	786
61.01	Total Other Tax & Misc. Expense	SUM	247	3,099	335	1,617	977	7,616
	Other Taxes & Misc Expenses							
62.01	Revenue Taxes	9.03	410	4,414	526	2,183	1,025	0
62.02	Adj B - Gain/Loss Property	20.06	-5	-58	-6	-32	-19	-149
62.03	Adj M - Exclude Franchise, Grt	9.03	-407	-4,384	-522	-2,168	-1,018	0
62.04	Misc Allowable Expenses	SUM	-2	-28	-2	-17	-12	-149

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Tax Calculations							
63.01	Present Revenues	PULL	1,548,047	1,434,802	913,814	63,561	2,646	367,531
63.02	Less O&M Expenses	PULL	-549,799	-503,134	-326,941	-20,915	-1,376	-123,709
63.03	Less Depreciation Expense	PULL	-347,624	-323,658	-199,542	-11,427	-554	-84,228
63.04	Less Other Tax and Misc Expenses	PULL	-98,595	-91,128	-57,620	-3,363	-165	-23,768
63.05	Net Income Before Taxes	SUM	552,029	516,881	329,711	27,857	550	135,826
63.06	Less Interest Sychronization	CALC	-101,592	-93,488	-59,245	-3,442	-154	-24,368
63.07	Additions & Deductions	20.06	95,492	87,958	55,463	3,184	149	23,070
63.08	Net Adjustments	SUM	-6,100	-5,531	-3,782	-258	-5	-1,297
63.09	State Taxable Income		545,929	511,350	325,929	27,599	545	134,529
63.10	Current State Income Tax		30,026	28,124	17,926	1,518	30	7,399
63.11	Federal Taxable Income		515,903	483,226	308,003	26,081	515	127,130
63.12	Current Federal Tax		180,566	169,129	107,801	9,128	180	44,495
63.13	Deferred Income Taxes	20.06	-35,590	-32,782	-20,671	-1,187	-55	-8,598
63.14	Amortization Of Investment Tax-Credits	20.06	-7,752	-7,140	-4,502	-258	-12	-1,873
63.15	Total Taxes	SUM	167,250	157,331	100,553	9,201	143	41,423

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Tax Calculations							
63.01	Present Revenues	PULL	4,191	45,148	5,423	22,088	10,401	113,245
63.02	Less O&M Expenses	PULL	-1,350	-17,139	-2,597	-5,652	-3,455	-46,665
63.03	Less Depreciation Expense	PULL	-842	-10,976	-1,075	-10,454	-4,560	-23,966
63.04	Less Other Tax and Misc Expenses	PULL	-245	-3,071	-333	-1,600	-965	-7,467
63.05	Net Income Before Taxes	SUM	1,754	13,962	1,418	4,382	1,421	35,148
63.06	Less Interest Sycbronization	CALC	-255	-3,059	-334	-1,593	-1,038	-8,104
63.07	Additions & Deductions	20.06	235	2,952	299	1,624	981	7,534
63.08	Net Adjustments	SUM	-19	-107	-35	31	-58	-570
63.09	State Taxable Income		1,735	13,855	1,383	4,412	1,363	34,578
63.10	Current State Income Tax		95	762	76	243	75	1,902
63.11	Federal Taxable Income		1,639	13,093	1,307	4,170	1,289	32,676
63.12	Current Federal Tax		574	4,583	457	1,459	451	11,437
63.13	Deferred Income Taxes	20.06	-88	-1,100	-112	-605	-366	-2,808
63.14	Amortization Of Investment Tax-Credits	20.06	-19	-240	-24	-132	-80	-612
63.15	Total Taxes	SUM	562	4,005	398	965	81	9,919

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	COST OF SERVICE SUMMARY							
64.01	Revenues at Present Rates	PULL	1,548,047	1,434,802	913,814	63,561	2,646	367,531
64.02	Less Expenses	PULL	-996,018	-917,921	-584,103	-35,704	-2,096	-231,705
64.03	Less Taxes	PULL	-167,250	-157,331	-100,553	-9,201	-143	-41,423
64.04	Net Income for Return	PULL	384,779	359,550	229,158	18,656	408	94,403
64.05	Rate Base	PULL	3,983,232	3,665,496	2,322,892	134,966	6,038	955,407
64.06	Earned Return on Rate Base	CALC	9.66%	9.81%	9.87%	13.82%	6.75%	9.88%
64.07	Requested Return on Rate Base %	PULL	9.809%	9.809%	9.809%	9.809%	9.809%	9.809%
64.08	Requested Return on Rate Base	CALC	390,730	359,562	227,861	13,239	592	93,719
64.09	Return Excess (Deficiency)	CALC	-5,951	-12	1,297	5,417	-185	683
64.10	Required Rev Incr (Decr)	CALC	9,688	19	-2,111	-8,818	301	-1,113

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
FPC ORIGINAL BASE CASE 75%/25%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	COST OF SERVICE SUMMARY							
64.01	Revenues at Present Rates	PULL	4,191	45,148	5,423	22,088	10,401	113,245
64.02	Less Expenses	PULL	-2,437	-31,186	-4,005	-17,706	-8,980	-78,097
64.03	Less Taxes	PULL	-562	-4,005	-398	-965	-81	-9,919
64.04	Net Income for Return	PULL	1,192	9,957	1,020	3,416	1,340	25,229
64.05	Rate Base	PULL	9,994	119,931	13,102	62,453	40,712	317,736
64.06	Earned Return on Rate Base	CALC	11.93%	8.30%	7.79%	5.47%	3.29%	7.94%
64.07	Requested Return on Rate Base %	PULL	9.809%	9.809%	9.809%	9.809%	9.809%	9.809%
64.08	Requested Return on Rate Base	CALC	980	11,764	1,285	6,126	3,994	31,168
64.09	Return Excess (Deficiency)	CALC	212	-1,807	-265	-2,710	-2,653	-5,939
64.10	Required Rev Incr (Decr)	CALC	-344	2,942	432	4,412	4,320	9,669

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Demand Factors							
1.01	Production Base - % * 1000		104,213	100,000	61,486	2,903	139	30,749
1.02	Ratio To Total Electric		100.00%	95.96%	59.00%	2.79%	0.13%	29.51%
1.03	Prod Intermediate - % * 1000		115,508	100,000	61,486	2,903	139	30,749
1.04	Ratio To Total Electric		100.00%	86.57%	53.23%	2.51%	0.12%	26.62%
1.05	Prod. Peaking - % * 1000		134,117	100,000	61,486	2,903	139	30,749
1.06	Ratio To Total Electric		100.00%	74.56%	45.85%	2.16%	0.10%	22.93%
1.07	Trans Avg 12 Cp - % * 1000		138,667	100,000	62,408	2,881	133	30,095
1.08	Ratio To Total Electric		100.00%	72.12%	45.01%	2.08%	0.10%	21.70%
1.09	Production Base, Retail Only		100,000	100,000	61,486	2,903	139	30,749
1.10	Ratio To Total Electric		100.00%	100.00%	61.49%	2.90%	0.14%	30.75%
	Energy Factors							
2.01	Energy Excl Whol D.A. - % * 1000		102,411	100,000	50,412	3,173	208	38,582
2.02	Ratio To Total Electric		100.00%	97.65%	49.23%	3.10%	0.20%	37.67%
2.03	Energy Excl D.A. Tall - % * 1000		106,312	100,000	50,412	3,173	208	38,582
2.04	Ratio To Total Electric		100.00%	94.06%	47.42%	2.98%	0.20%	36.29%
2.05	Recoverable Fuel - DA Wholesale		65,702	-	-	-	-	-
2.06	Recoverable Fuel - Allocable	2.02	844,314	824,439	415,616	26,159	1,715	318,085
2.07	Total Recoverable Fuel	SUM	910,016	824,439	415,616	26,159	1,715	318,085
2.08	Ratio		100.00%	90.60%	45.67%	2.87%	0.19%	34.95%
	Distribution							
3.01	Distrib Primary - % * 1000		100,473	100,000	63,753	3,595	98	28,038
3.02	Ratio To Total Electric		100.00%	99.53%	63.45%	3.58%	0.10%	27.91%
3.03	Distrib Secondary - % * 1000		100000	100,000	77150	5310	60	16,878
3.04	Ratio To Total Electric		100.00%	100.00%	77.15%	5.31%	0.06%	16.88%
3.05	Distrib Service - % * 1000		100000	100,000	88785	7222	712	3,256
3.06	Ratio To Total Electric		100.00%	100.00%	88.79%	7.22%	0.71%	3.26%
3.07	Distrib Meters - % * 1000		101149.053	100,000	79132	7173	548	12,523
3.08	Ratio To Total Electric		100.00%	98.86%	78.23%	7.09%	0.54%	12.38%
3.09	Distrib Light Fix - % * 1000		100000	100,000	0	0	0	0
3.10	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3.11	Distrib Light Poles - % * 1000		100000	100,000	0	0	0	0
3.12	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3.13	Distrib Is Equip - % * 1000		100000	100,000	0	0	0	0
3.14	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
	Customer Factors							
4.01	Number Of Retail Customers		1467983	1,467,983	1,293,722	104831	10379	47,529
4.02	Ratio To Total Electric		100.00%	100.00%	88.13%	7.14%	0.71%	3.24%
4.03	Meter Reading Exp - % * 1000		100955.035	100,000	86935	7049	612	4,327
4.04	Ratio To Total Electric		100.00%	99.05%	86.11%	6.98%	0.61%	4.29%
4.05	Cust Records Exp - % * 1000		100001	100,000	88129	7141	707	3,238
4.06	Ratio To Total Electric		100.00%	100.00%	88.13%	7.14%	0.71%	3.24%
4.07	Billing Expense - % * 1000		103275.912	100,000	84,930	6911	681	3,382
4.08	Ratio To Total Electric		100.00%	96.83%	82.24%	6.69%	0.66%	3.27%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Demand Factors							
1.01	Production Base - % * 1000		279	4,298	146	-	-	4,213
1.02	Ratio To Total Electric		0.27%	4.12%	0.14%	0.00%	0.00%	4.04%
1.03	Prod Intermediate - % * 1000		279	4,298	146	-	-	15,508
1.04	Ratio To Total Electric		0.24%	3.72%	0.13%	0.00%	0.00%	13.43%
1.05	Prod. Peaking - % * 1000		279	4,298	146	-	-	34,117
1.06	Ratio To Total Electric		0.21%	3.20%	0.11%	0.00%	0.00%	25.44%
1.07	Trans Avg 12 Cp - % * 1000		262	4,125	96	-	-	38,667
1.08	Ratio To Total Electric		0.19%	2.97%	0.07%	0.00%	0.00%	27.89%
1.09	Production Base, Retail Only		279	4,298	146	-	-	-
1.10	Ratio To Total Electric		0.28%	4.30%	0.15%	0.00%	0.00%	0.00%
	Energy Factors							
2.01	Energy Excl Whol D.A. - % * 1000		483	6,391	751	-	-	2,411
2.02	Ratio To Total Electric		0.47%	6.24%	0.73%	0.00%	0.00%	2.35%
2.03	Energy Excl D.A. Tall - % * 1000		483	6,391	751	-	-	6,312
2.04	Ratio To Total Electric		0.45%	6.01%	0.71%	0.00%	0.00%	5.94%
2.05	Recoverable Fuel - DA Wholesale		-	-	-	-	-	65,702
2.06	Recoverable Fuel - Allocable	2.02	3,982	52,690	6,192	-	-	19,875
2.07	Total Recoverable Fuel	SUM	3,982	52,690	6,192	-	-	85,577
2.08	Ratio		0.44%	5.79%	0.68%	0.00%	0.00%	9.40%
	Distribution							
3.01	Distrib Primary - % * 1000		480	3,295	741	-	-	473
3.02	Ratio To Total Electric		0.48%	3.28%	0.74%	0.00%	0.00%	0.47%
3.03	Distrib Secondary - % * 1000		1	147	454	0	0	0
3.04	Ratio To Total Electric		0.00%	0.15%	0.45%	0.00%	0.00%	0.00%
3.05	Distrib Service - % * 1000		0	3	22	0	0	0
3.06	Ratio To Total Electric		0.00%	0.00%	0.02%	0.00%	0.00%	0.00%
3.07	Distrib Meters - % * 1000		22	568	34	0	0	1,149
3.08	Ratio To Total Electric		0.02%	0.56%	0.03%	0.00%	0.00%	1.14%
3.09	Distrib Light Fix - % * 1000		0	0	0	100,000	0	0
3.10	Ratio To Total Electric		0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
3.11	Distrib Light Poles - % * 1000		0	0	0	0	100,000	0
3.12	Ratio To Total Electric		0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
3.13	Distrib Is Equip - % * 1000		0	100000	0	0	0	0
3.14	Ratio To Total Electric		0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
	Customer Factors							
4.01	Number Of Retail Customers		8	148	11,366	0	0	0
4.02	Ratio To Total Electric		0.00%	0.01%	0.77%	0.00%	0.00%	0.00%
4.03	Meter Reading Exp - % * 1000		54	1001	22	0	0	955
4.04	Ratio To Total Electric		0.05%	0.99%	0.02%	0.00%	0.00%	0.95%
4.05	Cust Records Exp - % * 1000		1	10	774	0	0	1
4.06	Ratio To Total Electric		0.00%	0.01%	0.77%	0.00%	0.00%	0.00%
4.07	Billing Expense - % * 1000		12	224	3,860	0	0	3,276
4.08	Ratio To Total Electric		0.01%	0.22%	3.74%	0.00%	0.00%	3.17%

Check Column

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
5.01	Transmission Plant							
5.02	Generation Step-Up Base	1.02	16,063	15,414	9,477	447	21	4,740
5.03	Generation Step-Up Intermediate	1.04	3,182	2,755	1,694	80	4	847
5.04	Generation Step-Up Peaking	1.06	15,622	11,648	7,162	338	16	3,582
5.05	Transmission	1.08	925,774	667,622	416,649	19,234	888	200,921
5.06	Total Transmission	SUM	960,641	697,438	434,982	20,100	929	210,089
5.07	Ratio		100.00%	72.60%	45.28%	2.09%	0.10%	21.87%
6.07	Distribution Plant							
6.08	Primary	3.02	1,171,725	1,166,206	743,491	41,925	1,143	326,981
6.09	Secondary	3.04	807,905	807,905	623,299	42,900	485	136,358
6.10	Services	3.06	327,389	327,389	290,672	23,644	2,331	10,660
6.11	Meters	3.08	138,081	136,512	108,025	9,792	748	17,095
6.12	Lighting Fixtures	3.10	122,903	122,903	0	0	0	0
6.13	Lighting Poles	3.12	74,247	74,247	0	0	0	0
6.14	IS Equipment	3.14	1,958	1,958	0	0	0	0
6.15	Total Distribution	SUM	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
6.16	Ratio		100.00%	99.73%	66.77%	4.47%	0.18%	18.57%
7.01	Customer Accounting							
7.02	Meter Reading	4.04	10,910	10,807	9,395	762	66	468
7.03	Customer Records	4.06	42,806	42,806	37,724	3,057	303	1,386
7.04	Billing	4.08	8,119	7,861	6,677	543	54	266
7.05	Total Customer Accounting	SUM	61,835	61,474	53,796	4,362	422	2,120
7.06	Ratio		100.00%	99.42%	87.00%	7.05%	0.68%	3.43%
	Wages And Salaries							
8.01	Prod. Demand - Base	1.02	43,590	41,828	25,718	1,214	58	12,862
8.02	Prod. Demand - Intermediate	1.04	7,416	6,420	3,948	186	9	1,974
8.03	Prod. Demand - Peaking	1.06	4,267	3,182	1,956	92	4	978
8.04	Production Energy - D.A.Wholesale	DA	991	0	0	0	0	0
8.05	Production Energy-Allocable	2.02	31,257	30,521	15,386	968	63	11,776
8.06	Transmission	5.07	12,797	9,291	5,795	268	12	2,799
8.07	Distribution	6.16	42,548	42,434	28,408	1,903	76	7,902
8.08	Total Ptd Wages & Salaries	SUM	142,866	133,676	81,211	4,632	223	38,291
8.09	Wtd Ptd Wage & Sal Ratios		100.00%	93.57%	56.84%	3.24%	0.16%	26.80%
8.10	Customer Accounting	7.06	14,715	14,629	12,802	1,038	100	504
8.11	Customer Serv & Info. Sales	4.02	3,505	3,505	3,089	250	25	113
8.12	Eccr	4.02	6,013	6,013	5,299	429	43	195
8.13	Total PTDCSS Wages & Salaries	SUM	167,099	157,823	102,401	6,350	391	39,103
8.14	Wtd PTDCSS Wage & Sal Ratios		100.00%	94.45%	61.28%	3.80%	0.23%	23.40%
8.15	Administrative & General	8.14	8,342	7,879	5,112	317	20	1,952
8.16	Total Wages And Salaries Exp	SUM	175,441	165,701	107,514	6,667	410	41,055
8.17	Wtd Wage And Salary Ratios		100.00%	94.45%	61.28%	3.80%	0.23%	23.40%
8.18	Retail Only Wage and Salary Ratios		100.00%	100.00%	64.88%	4.02%	0.25%	24.78%
9.01	Present Class Revenues	DA	1,509,008	1,397,246	886,989	61,766	2,542	359,989
9.02	Present Revenue Ratios		100.00%	92.59%	58.78%	4.09%	0.17%	23.86%
9.03	Retail only Ratios		100.00%	100.00%	63.48%	4.42%	0.18%	25.76%
10.01	Direct Assignment Wholesale		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
5.01	Transmission Plant							
5.02	Generation Step-Up Base	1.02	43	662	23	0	0	649
5.03	Generation Step-Up Intermediate	1.04	8	118	4	0	0	427
5.04	Generation Step-Up Peaking	1.06	32	501	17	0	0	3,974
5.05	Transmission	1.08	1,749	27,539	641	0	0	258,152
5.06	Total Transmission	SUM	1,832	28,821	684	0	0	263,203
5.07	Ratio		0.19%	3.00%	0.07%	0.00%	0.00%	27.40%
6.07	Distribution Plant							
6.08	Primary	3.02	5,598	38,426	8,642	0	0	5,519
6.09	Secondary	3.04	8	1,188	3,668	0	0	0
6.10	Services	3.06	0	10	72	0	0	0
6.11	Meters	3.08	30	775	46	0	0	1,569
6.12	Lighting Fixtures	3.10	0	0	0	122,903	0	0
6.13	Lighting Poles	3.12	0	0	0	0	74,247	0
6.14	IS Equipment	3.14	0	1,958	0	0	0	0
6.15	Total Distribution	SUM	5,636	42,357	12,428	122,903	74,247	7,087
6.16	Ratio		0.21%	1.60%	0.47%	4.65%	2.81%	0.27%
7.01	Customer Accounting							
7.02	Meter Reading	4.04	6	108	2	0	0	103
7.03	Customer Records	4.06	0	4	331	0	0	0
7.04	Billing	4.08	1	18	303	0	0	258
7.05	Total Customer Accounting	SUM	7	130	637	0	0	361
7.06	Ratio		0.01%	0.21%	1.03%	0.00%	0.00%	0.58%
	Wages And Salaries							
8.01	Prod. Demand - Base	1.02	117	1,798	61	0	0	1,762
8.02	Prod. Demand - Intermediate	1.04	18	276	9	0	0	996
8.03	Prod. Demand - Peaking	1.06	9	137	5	0	0	1,085
8.04	Production Energy - D.A.Wholesale	DA	0	0	0	0	0	991
8.05	Production Energy-Allocable	2.02	147	1,951	229	0	0	736
8.06	Transmission	5.07	24	384	9	0	0	3,506
8.07	Distribution	6.16	91	682	200	1,978	1,195	114
8.08	Total Ptd Wages & Salaries	SUM	406	5,227	513	1,978	1,195	9,190
8.09	Wtd Ptd Wage & Sal Ratios		0.28%	3.66%	0.36%	1.38%	0.84%	6.43%
8.10	Customer Accounting	7.06	2	31	152	0	0	86
8.11	Customer Serv & Info. Sales	4.02	0	0	27	0	0	0
8.12	Eccr	4.02	0	1	47	0	0	0
8.13	Total PTDCSS Wages & Salaries	SUM	408	5,258	739	1,978	1,195	9,276
8.14	Wtd PTDCSS Wage & Sal Ratios		0.24%	3.15%	0.44%	1.18%	0.71%	5.55%
8.15	Administrative & General	8.14	20	263	37	99	60	463
8.16	Total Wages And Salaries Exp	SUM	428	5,521	776	2,076	1,254	9,740
8.17	Wtd Wage And Salary Ratios		0.24%	3.15%	0.44%	1.18%	0.71%	5.55%
8.18	Retail Only Wage and Salary Ratios		0.26%	3.33%	0.47%	1.25%	0.76%	0.00%
9.01	Present Class Revenues	DA	4,114	44,335	5,283	21,929	10,299	111,762
9.02	Present Revenue Ratios		0.27%	2.94%	0.35%	1.45%	0.68%	7.41%
9.03	Retail only Ratios		0.29%	3.17%	0.38%	1.57%	0.74%	
10.01	Direct Assignment Wholesale		0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	[redacted]		Total Electric	FPSC Jurisdiction			F	
	Production Plant							
16.01	Base	1.02	2,488,732	2,388,113	1,468,355	69,327	3,319	734,321
16.02	Intermediate	1.04	437,381	378,658	232,822	10,992	526	116,434
16.03	Peaking	1.06	530,639	395,655	243,272	11,486	550	121,660
16.04	Direct Wholesale	DA	5,508	0	0	0	0	0
16.05	Production Plant In Service	SUM	3,462,260	3,162,426	1,944,449	91,805	4,396	972,414
16.06	Ratio		100.00%	91.34%	56.16%	2.65%	0.13%	28.09%
	Transmission Plant							
17.01	Gen. Step-Up - Base	1.02	16,063	15,414	9,477	447	21	4,740
17.02	Gen. Step-Up - Intermediate	1.04	3,182	2,755	1,694	80	4	847
17.03	Gen. Step-Up - Peaking	1.06	15,622	11,648	7,162	338	16	3,582
17.04	Transmission	1.08	925,774	667,622	416,649	19,234	888	200,921
17.05	Transmission Plant In Service	SUM	960,641	697,438	434,982	20,100	929	210,089
17.06	Ratio		100.00%	72.60%	45.28%	2.09%	0.10%	21.87%
17.07	Total Prod & Trans Plant	SUM	4,422,901	3,859,864	2,379,432	111,905	5,325	1,182,503
17.08	Ratio		100.00%	87.27%	53.80%	2.53%	0.12%	26.74%
	Distribution Plant							
18.01	Primary	3.02	1,171,725	1,166,206	743,491	41,925	1,143	326,981
18.02	Secondary	3.04	807,905	807,905	623,299	42,900	485	136,358
18.03	Services	3.06	327,389	327,389	290,672	23,644	2,331	10,660
18.04	Meters	3.08	138,081	136,512	108,025	9,792	748	17,095
18.05	Lighting Fixtures	3.10	122,903	122,903	0	0	0	0
18.06	Lighting Poles	3.12	74,247	74,247	0	0	0	0
18.07	Is Equipment	3.14	1,958	1,958	0	0	0	0
18.08	Distribution Plant In Service	SUM	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
18.09	Ratio		100.00%	99.73%	66.77%	4.47%	0.18%	18.57%
19.01	Total Trans & Dist Plant	SUM	3,604,849	3,334,559	2,200,470	138,361	5,636	701,183
19.02	Total Gross Ptd Plant	SUM	7,067,109	6,496,985	4,144,919	230,166	10,032	1,673,598
19.03	Ratio		100.00%	91.93%	58.65%	3.26%	0.14%	23.68%
20.01	General & Intangible Plant							
20.02	Labor Related	8.17	340,041	321,164	208,383	12,922	795	79,574
20.03	Retail Customer Related (Css)	4.02	57,976	57,976	51,094	4,140	410	1,877
20.04	General Plant In Service	SUM	398,017	379,140	259,477	17,062	1,205	81,451
20.05	Gross Electric Plant In Service	SUM	7,465,126	6,876,125	4,404,396	247,228	11,237	1,755,049
20.06	GP Ratio		100.00%	92.11%	59.00%	3.31%	0.15%	23.51%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.		Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Production Plant							
16.01	Base	1.02	6,663	102,641	3,487	0	0	100,619
16.02	Intermediate	1.04	1,056	16,275	553	0	0	58,723
16.03	Peaking	1.06	1,104	17,005	578	0	0	134,984
16.04	Direct Wholesale	DA	0	0	0	0	0	5,508
16.05	Production Plant In Service	SUM	8,823	135,921	4,617	0	0	299,834
16.06	Ratio		0.25%	3.93%	0.13%	0.00%	0.00%	8.66%
	Transmission Plant							
17.01	Gen. Step-Up - Base	1.02	43	662	23	0	0	649
17.02	Gen. Step-Up - Intermediate	1.04	8	118	4	0	0	427
17.03	Gen. Step-Up - Peaking	1.06	32	501	17	0	0	3,974
17.04	Transmission	1.08	1,749	27,539	641	0	0	258,152
17.05	Transmission Plant In Service	SUM	1,832	28,821	684	0	0	263,203
17.06	Ratio		0.19%	3.00%	0.07%	0.00%	0.00%	27.40%
17.07	Total Prod & Trans Plant	SUM	10,656	164,742	5,302	0	0	563,037
17.08	Ratio		0.24%	3.72%	0.12%	0.00%	0.00%	12.73%
	Distribution Plant							
18.01	Primary	3.02	5,598	38,426	8,642	0	0	5,519
18.02	Secondary	3.04	8	1,188	3,668	0	0	0
18.03	Services	3.06	0	10	72	0	0	0
18.04	Meters	3.08	30	775	46	0	0	1,569
18.05	Lighting Fixtures	3.10	0	0	0	122,903	0	0
18.06	Lighting Poles	3.12	0	0	0	0	74,247	0
18.07	Is Equipment	3.14	0	1,958	0	0	0	0
18.08	Distribution Plant In Service	SUM	5,636	42,357	12,428	122,903	74,247	7,087
18.09	Ratio		0.21%	1.60%	0.47%	4.65%	2.81%	0.27%
19.01	Total Trans & Dist Plant	SUM	7,468	71,178	13,112	122,903	74,247	270,290
19.02	Total Gross Ptd Plant	SUM	16,291	207,099	17,730	122,903	74,247	570,124
19.03	Ratio		0.23%	2.93%	0.25%	1.74%	1.05%	8.07%
20.01	General & Intangible Plant							
20.02	Labor Related	8.17	830	10,701	1,503	4,024	2,431	18,877
20.03	Retail Customer Related (Css)	4.02	0	6	449	0	0	0
20.04	General Plant In Service	SUM	830	10,707	1,952	4,024	2,431	18,877
20.05	Gross Electric Plant In Service	SUM	17,122	217,806	19,682	126,927	76,678	589,001
20.06	GP Ratio		0.23%	2.92%	0.26%	1.70%	1.03%	7.89%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Depreciation							
	Production Plant							
21.01	Bas	1.02	1,423,300	1,365,756	839,749	39,648	1,898	419,956
21.02	Intermediate	1.04	383,807	332,277	204,304	9,646	462	102,172
21.03	Peaking	1.06	239,473	178,556	109,787	5,183	248	54,904
21.04	DA Wholesale	10.01	9,312	0	0	0	0	0
21.05	Adj G - Unfunded Nuc Decommissioning W/S	10.01	-2,286	0	0	0	0	0
21.06	Total Prod Deprec Reserve	SUM	2,053,606	1,876,589	1,153,839	54,477	2,608	577,032
	Transmission Plant							
22.01	Gen. Step-Up - Base	1.02	5,394	5,176	3,182	150	7	1,592
22.02	Gen. Step-Up - Intermediate	1.04	1,069	925	569	27	1	285
22.03	Gen. Step-Up - Peaking	1.06	5,246	3,912	2,405	114	5	1,203
22.04	Transmission	1.08	426,327	307,446	191,871	8,858	409	92,526
22.05	Total Trans Deprec Reserve	SUM	438,036	317,459	198,027	9,148	423	95,605
	Distribution Plant							
23.01	Primary	3.02	428,837	426,817	272,109	15,344	418	119,671
23.02	Secondary	3.04	335,976	335,976	259,205	17,840	202	56,706
23.03	Services	3.06	120,990	120,990	107,421	8,738	861	3,939
23.04	Meters	3.08	54,864	54,241	42,922	3,891	297	6,793
23.05	Lighting Fixtures	3.10	65,524	65,524	0	0	0	0
23.06	Lighting Poles	3.12	36,587	36,587	0	0	0	0
23.07	I: Equipment	3.14	918	918	0	0	0	0
23.08	Total Dist Deprec Reserve	SUM	1,043,696	1,041,053	681,657	45,813	1,779	187,109
	General & Intangible Plant							
24.01	L	8.17	140,726	132,914	86,240	5,348	329	32,932
24.02	(Css)	4.02	41,781	41,781	36,821	2,984	295	1,353
24.03	Total General Deprec Reserve	SUM	182,507	174,695	123,061	8,331	625	34,284
	Common & Other Plant							
25.01	Progress	20.06	4,942	4,552	2,916	164	7	1,162
25.01	Total Com & Other Plant	SUM	4,942	4,552	2,916	164	7	1,162
25.02	Total Accumulated Depreciation	SUM	3,722,787	3,414,347	2,159,500	117,934	5,442	895,192

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Accumulated Depreciation							
	Production Plant							
21.01	Base	1.02	3,810	58,700	1,994	0	0	57,544
21.02	Intermediate	1.04	927	14,281	485	0	0	51,530
21.03	Peaking	1.06	498	7,674	261	0	0	60,917
21.04	DA Wholesale	10.01	0	0	0	0	0	9,312
21.05	Adj G - Unfunded Nuc Decommissioning W/S	10.01	0	0	0	0	0	-2,286
21.06	Total Prod Deprec Reserve	SUM	5,236	80,656	2,740	0	0	177,017
	Transmission Plant							
22.01	Gen. Step-Up - Base	1.02	14	222	8	0	0	218
22.02	Gen. Step-Up - Intermediate	1.04	3	40	1	0	0	144
22.03	Gen. Step-Up - Peaking	1.06	11	168	6	0	0	1,334
22.04	Transmission	1.08	806	12,682	295	0	0	118,881
22.05	Total Trans Deprec Reserve	SUM	833	13,112	310	0	0	120,577
	Distribution Plant							
23.01	Primary	3.02	2,049	14,064	3,163	0	0	2,020
23.02	Secondary	3.04	3	494	1,525	0	0	0
23.03	Services	3.06	0	4	27	0	0	0
23.04	Meters	3.08	12	308	18	0	0	623
23.05	Lighting Fixtures	3.10	0	0	0	65,524	0	0
23.06	Lighting Poles	3.12	0	0	0	0	36,587	0
23.07	Is Equipment	3.14	0	918	0	0	0	0
23.08	Total Dist Deprec Reserve	SUM	2,064	15,787	4,733	65,524	36,587	2,643
	General & Intangible Plant							
24.01	Labor Related	8.17	343	4,429	622	1,666	1,006	7,812
24.02	Retail Customer Related (Css)	4.02	0	4	323	0	0	0
24.03	Total General Deprec Reserve	SUM	344	4,433	946	1,666	1,006	7,812
	Common & Other Plant							
25.01	Retirement Work In Progress	20.06	11	144	13	84	51	390
25.01	Total Com & Other Plant	SUM	11	144	13	84	51	390
25.02	Total Accumulated Depreciation	SUM	8,488	114,132	8,741	67,274	37,644	308,440

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	[illegible]	[illegible]	Gen Serv. 100% LF	[illegible]
	Production Plant							
26.01	Productior it In Service	PULL	3,462,260	3,162,426	1,944,449	91,805	4,396	972,414
26.02	Total Prod Deprec Reserv	PULL	-2,053,606	-1,876,589	-1,153,839	-54,477	-2,608	-577,032
26.03	Net Production Plant	SUM	1,408,654	1,285,837	790,610	37,328	1,787	395,382
	Transmission Plant							
27.01	Transmissi it In Service	PULL	960,641	697,438	434,982	20,100	929	210,089
27.02	Total Trans Deprec Reserve	PULL	-438,036	-317,459	-198,027	-9,148	-423	-95,605
27.03	Net Transmission Plant	SUM	522,605	379,980	236,955	10,952	507	114,484
	Distribution Plant							
28.01	Distribution Plant In Service	PULL	2,644,208	2,637,121	1,765,487	118,261	4,707	491,094
28.02	Total Dist Deprec Reserve	PULL	-1,043,696	-1,041,053	-681,657	-45,813	-1,779	-187,109
28.03	Net Distribution Plant	SUM	1,600,512	1,596,068	1,083,830	72,448	2,928	303,985
29.01	Net Ptd Plant	SUM	3,531,771	3,261,884	2,111,395	120,727	5,222	813,852
29.02	Net Trans & Dist Plant	SUM	2,123,117	1,976,047	1,320,786	83,400	3,435	418,470
	General & Intangible Plant							
30.01	General Pl n Service	PULL	398,017	379,140	259,477	17,062	1,205	81,451
30.02	Deprec	PULL	-182,507	-174,695	-123,061	-8,331	-625	-34,284
30.03	Net General & Intang Plant	SUM	215,510	204,445	136,416	8,731	581	47,166
	Common & Other Plant							
31.01	Total Com & Other P nt	PULL	-4,942	-4,552	-2,916	-164	-7	-1,162
31.01	Net Common & Other Plant	SUM	-4,942	-4,552	-2,916	-164	-7	-1,162
31.02	Net Electric Plant In Service	SUM	3,742,339	3,461,777	2,244,896	129,294	5,795	859,856

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Net Electric Plant							
	Production Plant							
26.01	Production Plant In Service	PULL	8,823	135,921	4,617	0	0	299,834
26.02	Total Prod Deprec Reserv	PULL	-5,236	-80,656	-2,740	0	0	-177,017
26.03	Net Production Plant	SUM	3,587	55,265	1,877	0	0	122,817
	Transmission Plant							
27.01	Transmission Plant In Service	PULL	1,832	28,821	684	0	0	263,203
27.02	Total Trans Deprec Reserve	PULL	-833	-13,112	-310	0	0	-120,577
27.03	Net Transmission Plant	SUM	999	15,708	375	0	0	142,625
	Distribution Plant							
28.01	Distribution Plant In Service	PULL	5,636	42,357	12,428	122,903	74,247	7,087
28.02	Total Dist Deprec Reserve	PULL	-2,064	-15,787	-4,733	-65,524	-36,587	-2,643
28.03	Net Distribution Plant	SUM	3,572	26,570	7,695	57,379	37,660	4,444
29.01	Net Ptd Plant	SUM	8,158	97,544	9,947	57,379	37,660	269,887
29.02	Net Trans & Dist Plant	SUM	4,571	42,279	8,069	57,379	37,660	147,070
	General & Intangible Plant							
30.01	General Plant In Service	PULL	830	10,707	1,952	4,024	2,431	18,877
30.02	Total General Deprec Reserve	PULL	-344	-4,433	-946	-1,666	-1,006	-7,812
30.03	Net General & Intang Plant	SUM	486	6,274	1,007	2,359	1,425	11,065
	Common & Other Plant							
31.01	Total Com & Other Plant	PULL	-11	-144	-13	-84	-51	-390
31.01	Net Common & Other Plant	SUM	-11	-144	-13	-84	-51	-390
31.02	Net Electric Plant In Service	SUM	8,633	103,674	10,940	59,654	39,034	280,562

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	O & M Expenses							
	Production O & M							
	Energy Related Prod O & M							
32.01	Non-Recoverable Fuel-Allocable	2.02	8,390	8,192	4,130	260	17	3,161
32.02	Direct Wholesale	10.01	5,476	0	0	0	0	0
32.03	Non-Fuel O&M - Allocable	2.02	74,521	72,767	36,683	2,309	151	28,075
32.04	Adj E - Last Core Nuclear Fuel	2.02	0	0	0	0	0	0
32.05	Total Energy Related	SUM	88,387	80,959	40,813	2,569	168	31,236
	Demand Related Prod O & M							
33.01	Base	1.02	97,408	93,470	57,471	2,713	130	28,741
33.02	Intermediate	1.04	15,756	13,641	8,387	396	19	4,194
33.03	Peaking	1.06	19,285	14,379	8,841	417	20	4,421
33.04	Direct Wholesale	10.01	12,388	0	0	0	0	0
33.05	Purchase Power-D.A. Retail	4.02	4,412	4,412	3,888	315	31	143
33.06	Adj F-Nuclear M&S Inventory	1.02	0	0	0	0	0	0
33.07	Total Demand Related	SUM	149,249	125,902	78,587	3,842	200	37,500
33.07	Total Production O & M	SUM	237,636	206,861	119,401	6,411	368	68,735
	Transmission O & M							
34.01	Gen. Step-Up - Base	1.02	463	444	273	13	1	137
34.02	Gen. Step-Up - Intermediate	1.04	91	79	49	2	0	24
34.03	Gen. Step-Up - Peaking	1.06	450	336	206	10	0	103
34.04	Transmission	1.08	26,470	19,089	11,913	550	25	5,745
34.05	Total Transmission O & M	SUM	27,475	19,948	12,441	575	27	6,009
34.06	Ratio		100.00%	72.61%	45.28%	2.09%	0.10%	21.87%
	Distribution O & M							
35.01	Primary	3.02	39,592	39,405	25,122	1,417	39	11,048
35.02	Secondary	3.04	18,046	18,046	13,922	958	11	3,046
35.03	Services Incl R/D	3.06	15,342	15,342	13,622	1,108	109	500
35.04	Meters	3.08	3,403	3,364	2,662	241	18	421
35.05	Lighting Fixtures	3.10	3,530	3,530	0	0	0	0
35.06	Lighting Poles	3.12	2,176	2,176	0	0	0	0
35.07	Is Equipment	3.14	80	80	0	0	0	0
35.08	Total Distribution O & M	SUM	82,168	81,943	55,328	3,724	177	15,015

Line No.	Allocators	Alloc.	Curtailable Service			Lighting Fixture/Maint.	Lighting Poles	FERC
	Expenses							
	Production O & M							
	Energy Related Prod O & M							
32.01	Non-Recoverable Fuel-Allocable	2.02	40	524	62	0	0	198
32.02	Direct Wholesale	10.01	0	0	0	0	0	5,476
32.03	Non-Fuel O&M - Allocable	2.02	351	4,651	546	0	0	1,754
32.04	Adj E - Last Core Nuclear Fuel	2.02	0	0	0	0	0	0
32.05	Total Energy Related	SUM	391	5,174	608	0	0	7,428
	Demand Related Prod O & M							
33.01	Base	1.02	261	4,017	136	0	0	3,938
33.02	Intermediate	1.04	38	586	20	0	0	2,115
33.03	Peaking	1.06	40	618	21	0	0	4,906
33.04	Direct Wholesale	10.01	0	0	0	0	0	12,388
33.05	Purchase Power-D.A. Retail	4.02	0	0	34	0	0	0
33.06	Adj F-Nuclear M&S Inventory	1.02	0	0	0	0	0	0
33.07	Total Demand Related	SUM	339	5,222	212	0	0	23,347
33.07	Total Production O & M	SUM	730	10,396	820	0	0	30,775
	Transmission O & M							
34.01	Gen. Step-Up - Base	1.02	1	19	1	0	0	19
34.02	Gen. Step-Up - Intermediate	1.04	0	3	0	0	0	12
34.03	Gen. Step-Up - Peaking	1.06	1	14	0	0	0	115
34.04	Transmission	1.08	50	787	18	0	0	7,381
34.05	Total Transmission O & M	SUM	52	824	20	0	0	7,527
34.06	Ratio		0.19%	3.00%	0.07%	0.00%	0.00%	27.39%
	Distribution O & M							
35.01	Primary	3.02	189	1,298	292	0	0	186
35.02	Secondary	3.04	0	27	82	0	0	0
35.03	Services Incl R/D	3.06	0	0	3	0	0	0
35.04	Meters	3.08	1	19	1	0	0	39
35.05	Lighting Fixtures	3.10	0	0	0	3,530	0	0
35.06	Lighting Poles	3.12	0	0	0	0	2,176	0
35.07	Is Equipment	3.14	0	80	0	0	0	0
35.08	Total Distribution O & M	SUM	190	1,425	378	3,530	2,176	225

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Customer Accounting							
36.01	Meter Reading	4.04	10,910	10,807	9,395	762	66	468
36.02	Customer Records	4.06	42,806	42,806	37,724	3,057	303	1,386
36.03	Billing	4.08	6,416	6,212	5,276	429	42	210
36.04	Service Work For Conp	3.06	1,703	1,703	1,512	123	12	55
36.05	Uncollectibles	9.03	4,165	4,165	2,644	184	8	1,073
36.06	Total Customer Accounting Exp	SUM	66,000	65,693	56,551	4,555	431	3,192
37.01	Customer Service & Information	4.02	5,041	5,041	4,443	360	36	163
38.01	Sales	4.02	4,316	4,316	3,804	308	31	140
38.02	Economic Development Adjustment	4.02	-20	-20	-18	-1	0	-1
38.03	Total Sales	SUM	4,296	4,296	3,786	307	30	139
	Administrative & General Expenses							
39.01	Production-Base	1.02	-2,830	-2,716	-1,670	-79	-4	-835
39.02	Transmission	1.08	200	144	90	4	0	43
39.03	Distribution	18.09	1,800	1,795	1,202	81	3	334
39.04	Gross Plant Related	20.06	3,920	3,611	2,313	130	6	922
39.05	Labor Related	8.17	38,679	36,532	23,703	1,470	90	9,051
39.06	DA Wholesale	10.01	392	0	0	0	0	0
39.07	Retail Labor	8.18	292	292	189	12	1	72
39.08	Rate Case Expense Adjustment	9.03	206	206	131	9	0	53
39.09	Adj to Advertising	8.17	-4,007	-3,785	-2,456	-152	-9	-928
39.10	Adj to Industry Association Dues	8.17	-3	-3	-2	0	0	-1
39.11	Adj for Interest Tax Deficiency	20.06	-1,574	-1,450	-929	-52	-2	-370
39.12	Acquisition Adjustment	8.17	21,437	20,247	13,137	815	50	5,017
39.13	Total Administrative and General	SUM	58,512	54,874	35,709	2,236	135	13,349
40.01	Total O&M Expenses	SUM	481,128	438,656	287,659	18,168	1,204	106,603
40.02	Ratio		100.00%	91.17%	59.79%	3.78%	0.25%	22.16%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Customer Accounting							
36.01	Meter Reading	4.04	6	108	2	0	0	103
36.02	Customer Records	4.06	0	4	331	0	0	0
36.03	Billing	4.08	1	14	240	0	0	204
36.04	Service Work For Conp	3.06	0	0	0	0	0	0
36.05	Uncollectibles	9.03	12	132	16	65	31	0
36.06	Total Customer Accounting Exp	SUM	19	259	590	65	31	307
37.01	Customer Service & Information	4.02	0	1	39	0	0	0
38.01	Sales	4.02	0	0	33	0	0	0
38.02	Economic Development Adjustment	4.02	0	0	0	0	0	0
38.03	Total Sales	SUM	0	0	33	0	0	0
	Administrative & General Expenses							
39.01	Production-Base	1.02	-8	-117	-4	0	0	-114
39.02	Transmission	1.08	0	6	0	0	0	56
39.03	Distribution	18.09	4	29	8	84	51	5
39.04	Gross Plant Related	20.06	9	114	10	67	40	309
39.05	Labor Related	8.17	94	1,217	171	458	277	2,147
39.06	DA Wholesale	10.01	0	0	0	0	0	392
39.07	Retail Labor	8.18	1	10	1	4	2	0
39.08	Rate Case Expense Adjustment	9.03	1	7	1	3	2	0
39.09	Adj to Advertising	8.17	-10	-126	-18	-47	-29	-222
39.10	Adj to Industry Association Dues	8.17	0	0	0	0	0	0
39.11	Adj for Interest Tax Deficiency	20.06	-4	-46	-4	-27	-16	-124
39.12	Acquisition Adjustment	8.17	52	675	95	254	153	1,190
39.13	Total Administrative and General	SUM	140	1,768	261	794	480	3,638
40.01	Total O&M Expenses	SUM	1,132	14,673	2,140	4,389	2,686	42,472
40.02	Ratio		0.24%	3.05%	0.44%	0.91%	0.56%	8.83%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Rate Base Adjustments							
	Additive Adjustments							
	Plant Held For Future Use							
41.01	Transmission	1.08	6,602	4,761	2,971	137	6	1,433
41.02	Distribution	3.02	1,673	1,665	1,062	60	2	467
41.03	Total Land Held For Future Use	SUM	8,275	6,426	4,033	197	8	1,900
	Construction Work In Progress							
42.01	Production	16.06	100,598	91,886	56,497	2,667	128	28,254
42.02	Transmission	1.08	25,236	18,199	11,358	524	24	5,477
42.03	Distribution	18.09	17,907	17,859	11,956	801	32	3,326
42.04	General	8.17	5,731	5,413	3,512	218	13	1,341
42.05	Adj C - Remove Afud Cwip Prod	16.06	-66,597	-60,830	-37,402	-1,766	-85	-18,705
42.06	Total Rate Base Cwip	SUM	82,875	72,527	45,921	2,445	113	19,693
43.01	Total Additive Adjustments	SUM	91,150	78,953	49,954	2,642	121	21,593
43.02	Net Original Cost Rate Base	SUM	3,833,489	3,540,731	2,294,850	131,936	5,916	881,449
	Working Capital							
	Materials And Supplies							
	Fuel Supplies							
44.01	Amount Allocable	2.08	139,178	126,090	63,564	4,001	262	48,648
44.02	DA Wholesale Tallahassee	10.01	780	0	0	0	0	0
44.03	Adj E-Last Core Nuclear Fuel	2.02	0	0	0	0	0	0
44.04	Total Fuel Stocks	SUM	139,958	126,090	63,564	4,001	262	48,648
	Plant Materials & Supplies							
45.01	Amount Allocable	20.06	91,721	84,484	54,115	3,038	138	21,564
45.02	DA Wholesale Tallahassee	10.01	394	0	0	0	0	0
45.03	Adj F-Nuclear M&S Inventory	20.06	0	0	0	0	0	0
45.04	Total Plant Materials & Suppl	SUM	92,115	84,484	54,115	3,038	138	21,564
41.04	Total Materials & Supplies	SUM	232,073	210,574	117,679	7,038	400	70,212
46.01	Prepayments	19.03	219,710	201,985	128,862	7,156	312	52,031
	Miscellaneous Working Capital							
47.01	OPEB - D.A. Retail	8.18	-136,685	-136,685	-88,687	-5,499	-339	-33,866
47.02	OPEB - DA Wholeale	10.01	678	0	0	0	0	0
47.03	D.A. Retail-Doe D&D Nuclear	1.10	9,922	9,922	6,101	288	14	3,051
47.04	Misc Other	40.02	-180,952	-164,978	-108,188	-6,833	-453	-40,093
47.05	Adj B - Gain/Loss Property	20.06	-2,865	-2,639	-1,690	-95	-4	-674
47.06	Adj J - Retail Rate Case Exp	9.03	189	189	120	8	0	49
47.07	Transmission Deferral, Net of Tax	34.06	2,092	1,519	947	44	2	458
47.08	Adj	20.06	8,995	8,285	5,307	298	14	2,115
47.09	Total Misc Work Capital	SUM	-298,626	-284,387	-186,090	-11,789	-766	-68,961
48.01	Total Working Capital	SUM	153,157	128,172	60,451	2,405	-54	53,281
	Preliminary Summary							
49.01	Total Additive Adjustments		91,150	78,953	49,954	2,642	121	21,593
49.02	Working Capital		153,157	128,172	60,451	2,405	-54	53,281
49.03	Total Rate Base Adjustments		244,307	207,126	110,405	5,046	67	74,874
	Rate Base Calculation							
49.04	Net Electric Plan Service		3,742,339	3,461,777	2,244,896	129,294	5,795	859,856
49.05	Adjustments		244,307	207,126	110,405	5,046	67	74,874
49.06	Total Rate Base		3,986,646	3,668,903	2,355,301	134,341	5,862	934,731
49.07	Ratio		100.00%	92.03%	59.08%	3.37%	0.15%	23.45%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Rate Base Adjustments							
	Additive Adjustments							
	Plant Held For Future Use							
41.01	Transmission	1.08	12	196	5	0	0	1,841
41.02	Distribution	3.02	8	55	12	0	0	8
41.03	Total Land Held For Future Use	SUM	20	251	17	0	0	1,849
	Construction Work In Progress							
42.01	Production	16.06	256	3,949	134	0	0	8,712
42.02	Transmission	1.08	48	751	17	0	0	7,037
42.03	Distribution	18.09	38	287	84	832	503	48
42.04	General	8.17	14	180	25	68	41	318
42.05	Adj C - Remove Afud Cwip Prod	16.06	-170	-2,614	-89	0	0	-5,767
42.06	Total Rate Base Cwip	SUM	186	2,553	172	900	544	10,348
43.01	Total Additive Adjustments	SUM	207	2,804	189	900	544	12,197
43.02	Net Original Cost Rate Base	SUM	8,840	106,477	11,130	60,554	39,578	292,758
	Working Capital							
	Materials And Supplies							
	Fuel Supplies							
44.01	Amount Allocable	2.08	609	8,058	947	0	0	13,088
44.02	DA Wholesale Tallahassee	10.01	0	0	0	0	0	780
44.03	Adj E-Last Core Nuclear Fuel	2.02	0	0	0	0	0	0
44.04	Total Fuel Stocks	SUM	609	8,058	947	0	0	13,868
	Plant Materials & Supplies							
45.01	Amount Allocable	20.06	210	2,676	242	1,560	942	7,237
45.02	llahassee	10.01	0	0	0	0	0	394
45.03	Adj Inventory	20.06	0	0	0	0	0	0
45.04	Total Plant Materials & Suppl	SUM	210	2,676	242	1,560	942	7,631
41.04	Total Materials & Supplies	SUM	819	10,734	1,189	1,560	942	21,499
46.01	Prepayments	19.03	506	6,439	551	3,821	2,308	17,725
	Miscellaneous Working Capital							
47.01	OPEB - D.A. Retail	8.18	-353	-4,554	-640	-1,713	-1,035	0
47.02	OPEB - DA Wholeale	10.01	0	0	0	0	0	678
47.03	D.A. Retail-Doe D&D Nuclear	1.10	28	426	14	0	0	0
47.04	Misc Other	40.02	-426	-5,519	-805	-1,651	-1,010	-15,974
47.05	Adj B - Gain/Loss Property	20.06	-7	-84	-8	-49	-29	-226
47.06	Adj J - Retail Rate Case Exp	9.03	1	6	1	3	1	0
47.07	Transmission Deferral, Net of Tax	34.06	4	63	1	0	0	573
47.08	Adj K - Section 1341	20.06	21	262		153	92	710
47.09	Total Misc Work Capital	SUM	-733	-9,399	-1,412	-3,256	-1,981	-14,239
48.01	Total Working Capital	SUM	593	7,774	328	2,124	1,270	24,985
	Preliminary Summary							
49.01	Total Additive djustments		207	2,804	189	900	544	12,197
49.02	Total Working Capital		593	7,774	328	2,124	1,270	24,985
49.03	Total Rate Base Adjustments		800	10,578	517	3,024	1,814	37,181
	Rate Base Calculation							
49.04	Ne lectric Plant I Service		8,633	103,674	10,940	59,654	39,034	280,562
49.05	Adjustments		800	10,578	517	3,024	1,814	37,181
49.06	Total Rate Base		9,434	114,252	11,458	62,678	40,848	317,743
49.07	Ratio		0.24%	2.87%	0.29%	1.57%	1.02%	7.97%

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
51.01	Present Class Revenues	DA	1,509,008	1,397,246	886,989	61,766	2,542	359,989
	Revenue Credits							
52.01	Production Demand Related	16.06	2,325	2,124	1,306	62	3	653
52.02	Transmission Related	1.08	1,118	806	503	23	1	243
52.03	Distribution Plant Related	3.02	6,773	6,741	4,298	242	7	1,890
52.04	Gross Plant Related	20.06	1,812	1,669	1,069	60	3	426
52.05	Rate Base Related	49.07	8,160	7,510	4,821	275	12	1,913
52.06	Energy Non-Fuel Related	2.04	2,424	2,280	1,149	72	5	880
52.07	Distribution Services	3.06	9,560	9,560	8,488	690	68	311
52.08	Distribution Secondary	3.04	6,720	6,720	5,184	357	4	1,134
52.09	Customer Accounting	4.06	147	147	130	10	1	5
52.10	Total Revenue Credits	SUM	39,039	37,557	26,948	1,792	103	7,455
53.01	Total Present Revenues	SUM	1,548,047	1,434,803	913,937	63,558	2,645	367,444

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
51.01	Present Class Revenues	DA	4,114	44,335	5,283	21,929	10,299	111,762
	Revenue Credits							
52.01	Production Demand Related	16.06	6	91	3	0	0	201
52.02	Transmission Related	1.08	2	33	1	0	0	312
52.03	Distribution Plant Related	3.02	32	222	50	0	0	32
52.04	Gross Plant Related	20.06	4	53	5	31	19	143
52.05	Rate Base Related	49.07	19	234	23	128	84	650
52.06	Energy Non-Fuel Related	2.04	11	146	17	0	0	144
52.07	Distribution Services	3.06	0	0	2	0	0	0
52.08	Distribution Secondary	3.04	0	10	31	0	0	0
52.09	Accounting	4.06	0	0	1	0	0	0
52.10	Total Revenue Credits	SUM	75	789	133	159	102	1,482
53.01	Total Present Revenues	SUM	4,189	45,124	5,416	22,088	10,401	113,244

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Depreciation Expense							
	Production Depreciation							
54.01	Base	1.02	115,509	110,839	68,150	3,218	154	34,082
54.02	Intermediate	1.04	23,365	20,228	12,437	587	28	6,220
54.03	Peaking	1.06	22,922	17,091	10,509	496	24	5,255
54.04	DA Wholesale	10.1	538	0	0	0	0	0
54.05	D.A. Retail	1.10	8,733	8,733	5,370	254	12	2,685
54.06	Adj L - Accel Amort Tiger Bay	1.10	0	0	0	0	0	0
54.07	Total Production Deprec Exp		171,067	156,891	96,466	4,555	218	48,242
	Transmission Depreciation							
55.01	Gen. Step-Up - Base	1.02	477	458	281	13	1	141
55.02	Gen. Step-Up - Intermediate	1.04	94	81	50	2	0	25
55.03	Gen. Step-Up - Peaking	1.06	464	346	213	10	0	106
55.04	Transmission	1.08	28,831	20,791	12,976	599	28	6,257
55.05	Total Trans Deprec Exp	SUM	29,866	21,677	13,520	625	29	6,529
	Distribution Depreciation							
56.01	Primary	3.02	40,494	40,303	25,695	1,449	39	11,300
56.02	Secondary	3.04	34,997	34,997	27,000	1,858	21	5,907
56.03	Services	3.06	12,284	12,284	10,906	887	87	400
56.04	Meters	3.08	5,134	5,076	4,016	364	28	636
56.05	Lighting Fixtures	3.1	10,166	10,166	0	0	0	0
56.06	Lighting Poles	3.12	4,386	4,386	0	0	0	0
56.07	Equipment	3.14	90	90	0	0	0	0
56.08	Total Dist Deprec Expense	SUM	107,551	107,302	67,618	4,558	176	18,243
	General & Intang Depreciation							
57.01	Labor Related	8.17	26,550	25,076	16,270	1,009	62	6,213
57.02	Retail Customer Related (Css)	4.02	5,798	5,798	5,110	414	41	138
57.03	Adj Sebring	8.17	-2,208	-2,085	-1,353	-84	-5	-517
57.04	Total General Deprec Expense	SUM	30,140	28,789	20,027	1,339	98	5,884
58.01	Total Depreciation Expense	SUM	338,624	314,658	197,630	11,077	521	78,898

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Depreciation Expense							
	Production Depreciation							
54.01	Base	1.02	309	4,764	162	0	0	4,670
54.02	Intermediate	1.04	56	869	30	0	0	3,137
54.03	Peaking	1.06	48	735	25	0	0	5,831
54.04	DA Wholesale	10.1	0	0	0	0	0	538
54.05	D.A. Retail	1.10	24	375	13	0	0	0
54.06	Adj L - Accel Amort Tiger Bay	1.10	0	0	0	0	0	0
54.07	Total Production Deprec Exp		438	6,743	229	0	0	14,176
	Transmission Depreciation							
55.01	Gen. Step-Up - Base	1.02	1	20	1	0	0	19
55.02	Gen. Step-Up - Intermediate	1.04	0	3	0	0	0	13
55.03	Gen. Step-Up - Peaking	1.06	1	15	1	0	0	118
55.04	Transmission	1.08	54	858	2	0	0	8,040
55.05	Total Trans Deprec Exp	SUM	57	896	21	0	0	8,189
	Distribution Depreciation							
56.01	Primary	3.02	193	1,328	299	0	0	191
56.02	Secondary	3.04	0	51	159	0	0	0
56.03	Services	3.06	0	0	3	0	0	0
56.04	Meters	3.08	1	29	2	0	0	58
56.05	Lighting Fixtures	3.1	0	0	0	10,166	0	0
56.06	Lighting Poles	3.12	0	0	0	0	4,386	0
56.07	Is Equipment	3.14	0	90	0	0	0	0
56.08	Total Dist Deprec Expense	SUM	195	1,499	462	10,166	4,386	249
	General & Intang Depreciation							
57.01	Labor Related	8.17	65	836	117	314	190	1,474
57.02	Retail Customer Related (Css)	4.02	0	1	45	0	0	0
57.03	Adj Sebring	8.17	-5	-69	-10	-26	-16	-123
57.04	Total General Deprec Expense	SUM	59	767	153	288	174	1,351
58.01	Total Depreciation Expense	SUM	749	9,904	865	10,454	4,560	23,966

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	Taxes Other Than Inc & Rev							
	Real Estate & Property Tax							
59.01	Amount Allocable	20.06	85,272	78,544	50,310	2,824	128	20,047
59.02	DA Wholesale	10.10	102	0	0	0	0	0
59.03	Total Real Est & Prop Tax	SUM	85,374	78,544	50,310	2,824	128	20,047
60.01	Payroll Tax	8.17	14,159	13,373	8,677	538	33	3,3[illegible]3
61.01	Total Other Tax & Misc. Expense	SUM	99,533	91,917	58,987	3,362	161	23,361
	Other Taxes & Misc Expenses							
62.01	Revenue Taxes	9.03	139,119	139,119	88,314	6,150	253	35,843
62.02	Adj B - Gain/Loss Property	20.06	-1,891	-1,742	-1,116	-63	-3	-445
62.03	Adj M - Exclude Franchise, Grt	9.03	-138,166	-138,166	-87,709	-6,108	-251	-35,597
62.04	Misc Allowable Expenses	SUM	-938	-789	-511	-20	-1	-199

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Taxes Other Than Inc & Rev							
	Real Estate & Property Tax							
59.01	Amount Allocable	20.06	196	2,488	225	1,450	876	6,728
59.02	DA Wholesale	10.10	0	0	0	0	0	102
59.03	Total Real Est & Prop Tax	SUM	196	2,488	225	1,450	876	6,830
60.01	Payroll Tax	8.17	35	446	63	168	101	786
61.01	Total Other Tax & Misc. Expense	SUM	230	2,934	287	1,617	977	7,616
	Other Taxes & Misc Expenses							
62.01	Revenue Taxes	9.03	410	4,414	526	2,183	1,025	0
62.02	Adj B - Gain/Loss Property	20.06	-4	-55	-5	-32	-19	-149
62.03	Adj	9.03	-407	-4,384	-522	-2,168	-1,018	0
62.04	Misc Allowable Expenses	SUM	-2	-25	-1	-17	-12	-149

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non D mand	Gen Serv. 100% LF	Gen. Serv. Demand
	Tax Calculations							
63.01	Present Revenues	PULL	1,548,047	1,434,803	913,937	63,558	2,645	367,444
63.02	Less O&M Expenses	PULL	-481,128	-438,656	-287,659	-18,168	-1,204	-106,603
63.03	Less Depreciation Expense	PULL	-338,624	-314,658	-197,630	-11,077	-521	-78,898
63.04	Less Other Tax and Misc Expenses	PULL	-98,595	-91,128	-58,476	-3,342	-160	-23,162
63.05	Net Income Before Taxes	SUM	629,700	590,360	370,171	30,972	760	158,780
63.06	Less Interest Sychronization	CALC	-101,679	-93,575	-60,072	-3,426	-150	-23,840
63.07	Additions & Deductions	20.06	95,492	87,958	56,340	3,162	144	22,450
63.08	Net Adjustments	SUM	-6,187	-5,618	-3,732	-264	-6	-1,390
63.09	State Taxable Income		623,513	584,743	366,439	30,708	754	157,390
63.10	Current State Income Tax		34,293	32,161	20,154	1,689	41	8,656
63.11	Federal Taxable Income		589,219	552,582	346,285	29,019	713	148,734
63.12	Current Federal Tax		206,227	193,404	121,200	10,157	249	52,057
63.13	Deferred Income Taxes	20.06	-35,590	-32,782	-20,998	-1,179	-54	-8,367
63.14	Amortization Of Investment Tax-Credits	20.06	-7,752	-7,140	-4,574	-257	-12	-1,822
63.15	Total Taxes	SUM	197,178	185,642	115,782	10,410	226	50,524

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	Tax Calculations							
63.01	Present Revenues	PULL	4,189	45,124	5,416	22,088	10,401	113,244
63.02	Less O&M Expenses	PULL	-1,132	-14,673	-2,140	-4,389	-2,686	-42,472
63.03	Less Depreciation Expense	PULL	-749	-9,904	-865	-10,454	-4,560	-23,966
63.04	Less Other Tax and Misc Expenses	PULL	-229	-2,909	-286	-1,600	-965	-7,467
63.05	Net Income Before Taxes	SUM	2,079	17,638	2,125	5,644	2,191	39,340
63.06	Less Interest Sychronization	CALC	-241	-2,914	-292	-1,599	-1,042	-8,104
63.07	Additions & Deductions	20.06	219	2,786	252	1,624	981	7,534
63.08	Net Adjustments	SUM	-22	-128	-40	25	-61	-570
63.09	State Taxable Income		2,058	17,510	2,084	5,669	2,130	38,770
63.10	Current State Income Tax		113	963	115	312	117	2,1[illegible]2
63.11	Federal Taxable Income		1,944	16,547	1,970	5,358	2,012	36,6[illegible]8
63.12	Current Federal Tax		681	5,792	689	1,875	704	12,823
63.13	Deferred Income Taxes	20.06	-82	-1,038	-94	-605	-366	-2,808
63.14	Amortization Of Investment Tax-Credits	20.06	-18	-226	-20	-132	-80	-612
63.15	Total Taxes	SUM	694	5,490	690	1,450	376	11,536

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
	COST OF SERVICE SUMMARY							
64.01	Revenues at Present Rates	PULL	1,548,047	1,434,803	913,937	63,558	2,645	367,444
64.02	Less Expenses	PULL	-918,347	-844,442	-543,766	-32,586	-1,885	-208,663
64.03	Less Taxes	PULL	-197,178	-185,642	-115,782	-10,410	-226	-50,524
64.04	Net Income for Return	PULL	432,522	404,718	254,389	20,562	534	108,257
64.05	Rate Base	PULL	3,986,646	3,668,903	2,355,301	134,341	5,862	934,731
64.06	Earned Return on Rate Base	CALC	10.85%	11.03%	10.80%	15.31%	9.11%	11.58%
64.07	Requested Return on Rate Base %	PULL	8.447%	8.447%	8.447%	8.447%	8.447%	8.447%
64.08	Requested Return on Rate Base	CALC	336,747	309,908	198,950	11,348	495	78,956
64.09	Return Excess (Deficiency)	CALC	95,775	94,810	55,439	9,214	39	29,301
64.10	Required Rev Incr (Decr)	CALC	-155,921	-154,351	-90,255	-15,001	-63	-47,702

FLORIDA POWER CORPORATION
ALLOCATED COST OF SERVICE STUDY
PROJECTED 2002 TEST YEAR
PUBLIX ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
	COST OF SERVICE SUMMARY							
64.01	Revenues at Present Rates	PULL	4,189	45,124	5,416	22,088	10,401	113,244
64.02	Less Expenses	PULL	-2,110	-27,486	-3,291	-16,444	-8,211	-73,905
64.03	Less Taxes	PULL	-694	-5,490	-690	-1,450	-376	-11,536
64.04	Net Income for Return	PULL	1,385	12,148	1,435	4,194	1,814	27,804
64.05	Rate Base	PULL	9,434	114,252	11,458	62,678	40,848	317,743
64.06	Earned Return on Rate Base	CALC	14.68%	10.63%	12.52%	6.69%	4.44%	8.75%
64.07	Requested Return on Rate Base %	PULL	8.447%	8.447%	8.447%	8.447%	8.447%	8.447%
64.08	Requested Return on Rate Base	CALC	797	9,651	968	5,294	3,450	26,839
64.09	Return Excess (Deficiency)	CALC	588	2,498	467	-1,100	-1,636	964
64.10	Required Rev Incr (Decr)	CALC	-957	-4,066	-761	1,791	2,664	-1,570