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January 18, 2002

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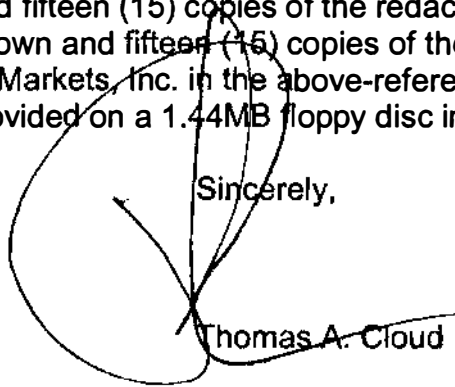
Blanca S. Bayó, Director
Division of Records and Reporting
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0870

Re: Docket No.: 000824-EI
Publix Super Market Inc., Direct Testimony of Sheree L. Brown and
Theodore Kury

Dear Ms. Bayó:

Enclosed please find fifteen (15) copies of the redacted version of the Direct
Testimony of Sheree L. Brown and fifteen (15) copies of the testimony of Theodore J.
Kury filed by Publix Super Markets, Inc. in the above-referenced docket. A copy of
these filings have been provided on a 1.44MB floppy disc in Word.

Sincerely,



Thomas A. Cloud

GRAY, HARRIS & ROBINSON, P.A.

AUS _____ TAC:gcj
CAF _____ Enclosures
CMP _____
COM *cc.* All individuals on docketing service list
CTR _____
ECR _____
GCL _____
OPC _____
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SEC _____
OTH *cc. pg*

Brown
DOCUMENT NUMBER-DATE
00685 JAN 18 08
FPSC-COMMISSION CLERK

Kury
DOCUMENT NUMBER-DATE
00686 JAN 18 08
FPSC-COMMISSION CLERK

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

Filed: January 18, 2002

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the redacted direct testimony of Sheree L. Brown and the direct testimony of Theodore J. Kury filed by Publix Super Markets, Inc. in the above-referenced docket has been furnished by U. S. Mail to the following parties of record and interested parties, this 18th day of January 2002:

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**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

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

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

DOCUMENT NUMBER-DATE

00685 JAN 18 08

FPSC-COMMISSION CLERK

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

1 Q: PLEASE STATE YOUR NAME AND OCCUPATION.

2 A: My name is Sheree L. Brown and I am a Managing Principal of SVBK Consulting Group,
3 Inc., a subsidiary of Alliant Energy Integrated Services, located at 710 N. Orange Ave., Suite
4 710, Orlando, Florida 32801.

5 Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

18 Q: ON WHOSE BEHALF ARE YOU SPONSORING THIS TESTIMONY?

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

20

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

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

32 Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

33 A: The purpose of my testimony is to address FPC's proposed revenue requirements for the
34 2002 Test Year. I will also address FPC's allocation of revenue requirements between rate
35 classes.

36 Q: PLEASE SUMMARIZE YOUR TESTIMONY.

37 A: My testimony addresses the proposal of FPC Witnesses Cicchetti and Myers to recover
38 merger-related Transition Expenses and Transaction Costs and to split the net merger savings
39 between the customers and FPC. I conclude that FPC has incorrectly allocated the
40 Transaction Costs to FPC and that the Transaction Costs should be reallocated to recognize
41 that a portion of the purchase price was directly attributable to the acquisition of Florida
42 Progress' unregulated businesses. I question the reasonableness of FPC's severance packages

43 paid to executives and the Company's request for the recovery of such costs through the
44 amortization of Transition Expenses. I explain that the benefits of the merger extend beyond
45 the estimated merger-related savings and will provide significant benefits to the shareholder.
46 I conclude that the amortization period requested by Witness Cicchetti is not justified and
47 propose to amortize the Transition Expenses over a 20 year period and the Transaction Costs
48 over a 40 year period, with a return at 7.5%. Lastly, I provide for a portion of earnings in
49 excess of the authorized rate of return to be applied to faster amortization of the Transition
50 Expenses and Transaction Costs.

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

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

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

70 **MERGER ADJUSTMENT**

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

73
74 A: Yes.

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

77
78 A: FPC Witnesses Cicchetti and Myers are proposing to increase the Test Year revenue
79 requirements by \$58.7 million to remove FPC’s estimated merger-related savings which FPC
80 claims were incorporated into the Test Year operating budget. They then propose to give the
81 retail customers an annual credit of \$5 million, reflecting approximately one-half of the net
82 savings they have calculated by offsetting the estimated merger-related savings by
83 amortization of Transition Expenses and Transaction Costs. This adjustment is explained as
84 follows:

85 1) Progress Energy is estimating total merger-related savings of \$175 million a year, with
86 \$58.7 million of those savings anticipated for FPC.

87 2) Since a large portion of the estimated savings is due to reductions in FPC’s labor force,
88 FPC is proposing to amortize \$69.676 million in severance costs which were incurred in
89 the labor force reduction as “Transition Expenses”. These severance costs are being

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

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

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

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

106

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 at a tax rate of 38.575%.

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

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

111

112 A: No. Witness Cicchetti stated that:

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

115

116 He further states that :

117

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

122

123 Although FPC is not proposing to include the Transaction Costs in rate base, his proposal is
124 very similar to including the Transaction Costs in rate base and *does* increase the rates paid
125 by the customer. Dr. Cicchetti is proposing to earn a return on the unamortized balance of
126 the Transaction Costs by amortizing the Transaction Costs at an effective rate of 7.5%, based
127 on the cost of Progress Energy’s merger-related debt. As explained earlier, the \$25.310
128 million in annual amortization proposed by Dr. Cicchetti must be grossed-up for taxes,
129 resulting in an annual revenue requirement of \$41.204 million.

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

134 Q: DO YOU HAVE ANY CONCERNS WITH THE MERGER ADJUSTMENT PROPOSED
135 BY WITNESSES CICCHETTI AND MYERS?
136

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

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

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

151 3) Witness Myers claims that merger savings are estimated to be \$58.7 million, therefore,
152 FPC has designed a method of recovering the Transition Expenses and Transaction Costs
153 that will result in net savings of \$9.85 million to “share” between the retail customers and
154 FPC. While FPC has indicated that numerous actions have been taken to result in the
155 estimated \$58.7 million in savings, isolating the true merger-related savings from savings
156 that could have been achievable even without the merger is an inaccurate exercise.

157 Based on the changes in FPC's operating and maintenance costs since the merger, the
158 claimed merger savings have been more than offset by increases in other costs. This
159 raises a question of whether the merger has really resulted in substantial savings that
160 justify the requested amortization of the Transition Expenses and Transaction Costs.

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

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

165
166 A: CP&L's reasons for the acquisition were set forth in Florida Progress' Notice of Annual
167 Meeting of Shareholders, July 5, 2000, at pages 48 through 50. A review of those reasons
168 shows that [REDACTED]

169 Among the reasons provided were:

170 (i) [REDACTED]

171 (ii) [REDACTED]

172 (iii) [REDACTED]

173 (iv) [REDACTED]

174 (v) [REDACTED]

175 In a Finance Committee presentation to CP&L given on August 4, 1999, page 7, "Wall Street
176 Highlights" listed several anticipated benefits, including [REDACTED]

177 These reports, along with several analysts' reports also indicated that [REDACTED].

178 In a merger announcement which was published on August 23, 1999, Mr. William
179 Cavanaugh, Chairman, President and Chief Executive Officer of CP&L recognized that the

180 acquisition would enhance CP&L's competitive position. The press release further
181 recognized that the combined companies' non-utility businesses were a strong supplement to
182 utility earnings growth and that non-utility revenues will represent approximately 15% of the
183 revenues of the combined company.

184 In CP&L's August 20, 1999 Minutes of Meeting of Board of Directors, it was noted that
185 [REDACTED] said:

186 [REDACTED]

187
188 In the CP&L Board of Directors Strategic Planning Retreat 1999 Background Materials, page
189 6, CPL indicated that [REDACTED]. It further noted that [REDACTED].

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

192
193 A: In a review of the Power Operations, Power Trading and Term Marketing functions,
194 the Company provided [REDACTED]

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

198
199 A: While cost savings were a major driving factor for the merger, these cost savings goals are
200 not just to provide benefits to the customers. The cost savings are also intended to place
201 CP&L and FPC in the best competitive position to capture a larger market share when
202 deregulation occurs. In addition, the Companies expect [REDACTED]. These benefits are
203 expected to increase shareholder value. The implications of the Company's goal to enhance
204 its competitive position and to [REDACTED] are that the method of recovering Transition
205 Expenses and Transaction Costs should recognize that there are many merger benefits to be

206 enjoyed by the shareholders, as well as those benefits that will accrue to the customers.
207 While all of these benefits have not been quantified, it is apparent that the Company is
208 positioning itself to maximize its earnings in the competitive utility market and will reap the
209 benefits of their strengthened competitive position for many years to come. These benefits
210 should be considered by the Commission when determining the appropriate regulatory
211 treatment of FPC's Transition Expenses and Transaction Costs.

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

217
218 A: FPC's Transition Expenses include approximately \$25 million in severance benefits paid to
219 FPC executives, including the President and Chief Executive Officer ("CEO"), the Vice
220 President and General Counsel, and the Vice President of Human Resources. The
221 Company's 1999 Federal Energy Regulatory Commission ("FERC") Form 1 provides the
222 salaries of the executives for 1999, including amounts earned under the management
223 incentive compensation plan. These payments are set forth in Table 1 below, along with the
224 severance packages provided to each, and the multiple of the executives' annual
225 compensation that was paid out in severance.

226

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

227
228

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.

231

232

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.

233

234

235

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

236

237

238

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.

239

240

241

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

242

243

244

A: Yes. The total merger-related savings included [REDACTED] 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,

245

246

247 however, the allocation does not recognize that the [REDACTED] are supported by the
248 production function and that additional Transition Expenses and Transaction Costs should be
249 allocated to the shareholders to recognize this support. Further, since the production function
250 is supported by the Shared Services, the allocation of Transition Expenses and Transaction
251 Costs should again recognize that the shareholders benefit from the costs which are borne by
252 the FPC and CP&L retail customers.

253 Q: DO YOU HAVE SUFFICIENT INFORMATION TO ISOLATE THE COSTS THAT
254 SUPPORT THE COMPANY'S EFFORTS TO [REDACTED]?

255
256 A: No. However, the Commission should recognize that this support is provided in making its
257 determination on the appropriate treatment of the Transition Expenses and Transaction Costs.

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

260
261 A: Apparently not. In response to several data requests, the Company provided a detailed
262 breakdown of the merger-related synergies. The total synergies shown on [REDACTED].
263 Several other versions of this document were developed, showing different levels of merger-
264 related synergies; however, to date, we have not seen a corresponding breakdown of the \$175
265 million. The breakdown of the merger-related synergies does include [REDACTED] but
266 does not include any savings attributable to Florida Progress' non-regulated businesses,
267 including Electric Fuels or Progress Telecomm.

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

270
271 A: [REDACTED]

272
273
274

275 Q: SHOULD ANY PORTION OF THE TRANSITION EXPENSES AND TRANSACTION
276 COSTS BE ALLOCATED TO THE NON-REGULATED BUSINESSES?
277

278 A: Yes. It is obvious that a portion of the purchase price applied to the non-regulated
279 businesses. As explained earlier, the achievement of cost savings is not the only benefit
280 derived by the merger. There is value in these subsidiaries that will accrue to the
281 shareholders and should be recognized in the allocation of merger-related costs. In the
282 Merrill Lynch analyses provided in OPC3 007376, Merrill Lynch showed [REDACTED].
283 The Transaction Costs should be allocated between the regulated and non-regulated
284 businesses based on the acquisition price. The regulated portion of the costs should then be
285 allocated to FPC based on the anticipated merger-related savings.

286 Q: WHAT ARE THE SAVINGS THAT FPC HAS ESTIMATED AND ATTRIBUTED TO
287 THE MERGER?
288

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

294

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

295

296

297

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.

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303

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

304

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306

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.

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314 Q: DID FPC'S ESTIMATED TEST YEAR EXPENSES ACTUALLY DECLINE FROM
315 HISTORICAL LEVELS DUE TO THE ESTIMATED MERGER-RELATED SAVINGS?
316

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

324 Q: COULD ANY OF THE ESTIMATED SAVINGS BE ACCOMPLISHED ON A STAND-
325 ALONE BASIS?
326

327 A: Apparently so. Document OPC3 00766 is a handout from the Board 2000 Strategic Planning
328 Seminar addressing [REDACTED]

329 Q: DO YOU HAVE ANY OTHER CONCERNS WITH FPC'S ESTIMATED MERGER-
330 RELATED SAVINGS?
331

332 A: Yes. A review of FPC's itemized breakdown of estimated merger-related expenses shows a
333 [REDACTED]. In response to Citizens Interrogatories 82 through 84, the Company listed
334 several benefits that were expanded to match CP&L benefits. These benefits are set forth in
335 Table 4 below:
336

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

337

338

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.

339

340

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.

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

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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

350

351

352

353 Progress Energy Services raises questions as to whether these claimed merger-related savings
 354 are simply “masking” other large increases that FPC is proposing to collect from its
 355 customers. FPC’s 2000 FERC Form 1 provides a breakdown of the Administrative and
 356 General expenses for 2000 and 1999. In order to provide a comparison of FPC’s recurring
 357 Administrative and General expenses, Table 5 below shows the total Administrative and
 358 General expenses for 2000 and 1999, exclusive of Employee Pensions and Benefits and the
 359 non-recurring merger-related severance payments incurred in 2000. Employee Pensions and
 360 Benefits have been removed due to the large impact of the Pension Credit and the high
 361 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

362 Schedule C-21, page 6 of 8, sets forth the Test Year 2002 Administrative and General
 363 Expenses of \$46,453,000. Removal of the pension credit increases this amount to
 364 \$95,474,000. In addition, FPC changed its method of accounting for certain costs after the
 365 merger, resulting in a reclassification of \$15,678,000 in additional Administrative and
 366 General expenses to other FERC accounts. To put 2002 expenses on a comparable basis to
 367 2000 and 1999, these expenses are added back to the Administrative and General expenses,
 368 resulting in a total 2002 Test Year expense of \$111,152,000. This level of Administrative
 369 and General Expenses is an increase of over \$37 million from 2000 to 2002, representing an

371 average increase of 22.49% per year. This would indicate that the level of increase for
372 recurring expenses is even greater than 22.49%. If this level of expense is “net” of FPC’s
373 claimed savings of \$24.8 million, then FPC’s costs before the merger savings would be rising
374 at a rate of 35.5% per year from 2000 to 2002. Thus, FPC’s claim of \$24.8 million in
375 savings due to shared corporate services is rather “lost” in the much larger increases that FPC
376 is asking the customers to absorb.

377 In addition to the increases demonstrated above for 2000 to 2002, the Company has also
378 increased its benefit packages due to implementation of new programs to “match” the
379 benefits provided by Progress Energy. As shown in Table 2 above, these new programs have
380 resulted in increases of \$4.7 million in the Test Year, while only [REDACTED] was
381 reflected in the merger savings estimates.

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

384
385 When compared to 1999 expense levels, the average growth in Administrative and General
386 expenses is 5.86% per year after merger-related savings and 13.2% assuming that merger-
387 savings were not realized. This comparison, however, does not recognize several reductions
388 in Administrative and General expenses that were achieved in 2000, including \$10.7 million
389 in Outside Services, \$4 million in Property Insurance, \$4.4 million in Administrative and
390 General salaries and \$2.9 million in General Advertising expenses. The Company also
391 expensed \$7.3 million for Y2K issues in 1999.

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396 Q: SHOULD THE COMMISSION ACCEPT WITNESS CICCHETTI'S AND WITNESS
397 MYERS' RECOMMENDED MERGER ADJUSTMENT?
398

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

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

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

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

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

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

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

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

425 In addition, it should be noted that, due to tax implications, the retail customers must pay
426 \$1.63 for every \$1.00 of Transaction Costs incurred by the Company. These factors should
427 be considered by the Commission in establishing a fair and equitable regulatory treatment for
428 FPC's Transition Expenses and Transaction Costs.

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

431
432 A: Yes. First, the Transaction Costs should be allocated between the regulated companies and
433 the non-regulated businesses based on a reasonable assessment of the fair value of the
434 companies and the price paid for the acquisition. The Transition Expenses and Transaction
435 Costs allocated to the regulated companies should be further allocated to FPC based on the
436 estimated merger synergies of FPC as compared to the total estimated merger synergies. The
437 reasonable FPC-related Transition Expenses should be amortized over a 20-year period with
438 no return on the unamortized balance. The Transaction Costs should be amortized over a 40
439 year period at the net of tax interest rate of 4.607% and grossed-up to allow FPC to pay taxes
440 on the revenue received. In addition, Publix Witness Kury has established an earnings
441 sharing provision. To the extent that FPC's earnings are in excess of the authorized rate of

442 return, the excess will be shared as set forth in Witness Kury's testimony, with FPC's share
443 going to accelerate amortization of the Transition Expenses and Transaction Costs on a
444 prorata basis.

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

448
449 A: Although the final treatment of the Transition Expenses and Transaction Costs would be
450 decided in the context of deregulation proceedings, the recovery of the Transition Expenses
451 and Transaction Costs should not be a "given" when determining any stranded cost charges
452 that may be applicable in the event of deregulation. As mentioned earlier in my testimony,
453 the merger has allowed the Company to position itself to be a stronger competitor in a
454 deregulated market. If, then, the retail market is deregulated, the Company should bear a
455 much greater share of the Transition Expenses and Transaction Costs incurred. Further, the
456 Commission should bear in mind that the recovery of the Transaction Costs is similar to
457 allowing the Company to recover costs for acquiring FPC at a price greatly exceeding the
458 book value of FPC, which is similar to a "stranded benefit". To allow this recovery and to
459 then also claim that the market value of the Company's assets is below book value, and that a
460 portion of the costs of such assets are then "stranded" is a double-whammy for FPC's
461 customers which should be taken into consideration in either the Commission's decision in
462 this proceeding regarding the recovery of Transaction Costs or in any future deregulation
463 proceeding.

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466

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

469
470 A: Yes. As explained earlier, FPC incurred \$69.676 million in severance costs and executive
471 payouts. While the executive payouts do not appear reasonable, I have calculated
472 amortization of the total \$69.676 million over a 20 year period. This amortization would
473 result in an annual revenue requirement of \$3,483,800 for the total system. As explained
474 earlier, if the Commission finds any portion of the severance costs to be unreasonable for
475 recovery by the retail customers, the amortization would be reduced accordingly. As shown
476 in Table 1 above, the total purchase price would be allocated 70% to the regulated companies
477 and 30% to non-regulated businesses. Applying 30% of the total Transaction Costs of
478 \$924.038 million to the unregulated businesses would leave \$646.827 million to be allocated
479 between the regulated companies. Of this amount, 30.9%, or \$199.869 million would be
480 allocated to FPC, based on the relative estimated merger-related savings.

481 Applying the retail jurisdictional allocation factor of 94.45% to the Transition Expenses and
482 Transaction Costs results in total jurisdictional Transition Expenses of \$3.29 million and
483 total jurisdictional Transaction Costs of \$188.776 million. Amortization of the Transaction
484 Costs over a 40 year period at the after tax interest rate of 4.607% would result in annual
485 amortization of \$10.416 million, which must then be grossed-up for taxes, resulting in a
486 revenue requirement of \$16.957 million for the retail customers. The combined revenue
487 requirement associated with the amortization of the Transition Expenses and the Transaction
488 Costs would be \$20.247 million. The impact of this adjustment is a reduction of \$35.194
489 million to the retail cost of service (elimination of the Company's proposed \$55.441 million

490 in merger adjustment to the retail jurisdiction less the \$20.247 million revenue requirement
491 associated with the amortization). Offsetting this reduction by the \$5 million credit proposed
492 by Witness Cicchetti provides a net retail revenue impact of \$30.194 million.

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

495

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

504 **DISTRIBUTION OPERATING AND MAINTENANCE EXPENSES**

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

508

509 A: The Company is projecting an increase of \$19.9 million (26%) in distribution operating and
510 maintenance expenses from 2000 to 2002. A portion of this increase is due to the
511 Company's accounting change in the allocation of benefits; therefore, if the benefits loading
512 adjustment of approximately \$1.956 million is removed from the calculation, the Distribution
513 expenses increased 23%. This increase is *net of* estimated merger synergies of \$5.5 million;
514 therefore, the projected increase without the estimated merger synergies would be \$25.4

515 million, or 33% (30% excluding the benefits loading change). FPC Witness Sipes provides
516 details of the Company's proposed distribution reliability initiatives, which are to be
517 implemented in the 2002 to 2004 time frame at a total capital cost of \$126.807 million and
518 total operating and maintenance costs of \$20.1 million. These distribution reliability
519 initiatives contributed \$7 million of the increase in distribution operating and maintenance
520 expenses for the Test Year.

521 Exhibit SLB-2 provides a historical breakdown of the Company's distribution expenses from
522 1996 through 2000 from the Company's FERC Form 1's as compared to the Test Year
523 projection. As shown on Exhibit SLB-2, FPC's total distribution costs rose from \$66.2
524 million in 1998 to \$76.6 million in 1999, then stayed relatively constant for 2000 at \$77.2
525 million. Exhibit C-12 shows 2001 projected expenses of \$74.7 million, even with the
526 benefits loading change which occurred in 2001.

527 As explained in Witness Sipes' testimony, the Company implemented another three year
528 distribution improvement program in 1999, which they called the "D2K" program. This
529 program included substantial improvements, which were described by Witness Sipes on
530 pages 6 through 8 of his testimony. The large increase of \$10.4 million in Distribution
531 operating and maintenance expenses from 1998 to 1999 should be partially explained by the
532 implementation of the D2K program. Since this was a three year program, it is reasonable to
533 assume that the extraordinary expenses associated with D2K would be eliminated in 2002—
534 then "replaced" by the new three-year program to increase system reliability. In fact,
535 Schedule C-65, page 7, shows \$3.8 million in consulting services alone which were
536 specifically identified as D2K related. Further, in his deposition on January 17, 2002, Mr.

537 Sipes indicated that FPC had spent approximately \$10 million on tree-trimming in 1999 and
538 \$9 million in 2000. Schedule C-12 shows \$11.1 million in 1999 and \$9.8 million in 2000.
539 Although FPC's costs for tree-trimming were between \$9 and \$11 million in 1999 and 2000,
540 the Company has treated its reliability initiative of \$1.6 million in vegetation management as
541 an incremental cost for 2002. Mr. Sipes also indicated that FPC would be hiring additional
542 employees or contract employees to implement the reliability initiatives; therefore, the
543 merger-related savings attributable to reductions in labor will be offset by increased staffing
544 in the Test Year.

545 Exhibit SLB-2 calculates the increase in Distribution operating and maintenance expenses
546 from 1998 to 1999 that would be expected based on application of general inflation and
547 customer growth rates. As shown on Exhibit SLB-2, the 1999 expenses attributable to
548 general inflation and customer growth would be \$69.17 million. The remainder of the actual
549 increase from 1998 to 1999 was \$7.473 million, which I assumed was attributable to the
550 D2K program. Escalating this amount to 2002 dollars and customer levels results in a total
551 of \$8.487 that could be attributed to the D2K program. Based on the Company's estimate of
552 \$7 million for the new reliability initiatives, the cost of reliability initiatives appears to be
553 declining. For purposes of my analyses, I assumed that this was a "wash". Therefore, I have
554 escalated the 2000 Distribution operating and maintenance expenses to 2002 dollars using
555 the GDP deflator and a customer growth factor. I then added back the benefits loading
556 adjustment and subtracted the Company's estimated merger-related savings. The result is a
557 Test Year operating and maintenance expense of \$82.168 million—which is \$15 million less
558 than the Company's Test Year projection.

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

568 **STORM DAMAGE EXPENSE AND RESERVE**

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

571
572 A: The Company has continued to accrue \$6 million to the storm damage fund, as authorized in
573 Order No. PSC-94-0852-FOF-EI. They have further assumed that the amount charged to the
574 reserve for storm damage will be equal to the accrual.

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

577
578 A: Yes. Given the current balance in the storm damage account and the Company's historical
579 storm damage experience, I believe the Commission should re-visit the level of annual
580 accrual to the storm damage fund. In response to Citizens' Interrogatory No. 92, the
581 Company provided its storm damage charges for 1997 through 2000. Table 6 below shows
582 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

583
584

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.

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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?

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599
600
601
602

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

603 balance by \$4 million. Account 190 accumulated deferred income taxes would increase by
604 the taxes on the \$4 million, or \$1.543 million, resulting in a total rate base adjustment of
605 \$2.457 million. This adjustment would decrease the total system revenue requirement by
606 \$392,320, assuming FPC's proposed return on equity of 13.2%. The retail jurisdiction
607 revenue requirement would be decreased by \$380,485.

608 **POWER MARKETING EXPENSES**

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

611

612 A: Yes. The Company has estimated Power Marketing expenses of \$4.897 million in the 2002

613 Test Year, which is an increase of 89.7% from the expense incurred in 2000, indicating an

614 annual growth of 37.7%. This amount has been allocated 100% to the retail jurisdiction.

615 Aside from the large increase in Power Marketing expenses, I have two concerns with the

616 allocation of the costs. First, FPC has failed to allocate any portion to the wholesale

617 jurisdiction, yet these customers benefit from the economy sales in the same manner as the

618 retail customers. Second, FPC has not absorbed any of the cost increase, yet FPC enjoys a

619 20% incentive on the margins created from increases in sales over the historical 3 year

620 average. This incentive was established in Order No. PSC-00-1744-PAA-EI and was

621 described on page 10 of the Order:

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

627

628 In addition, as explained earlier, the Company is expecting substantial benefits from

629 expanded competitive wholesale sales. It is not clear whether the Power Marketing expenses
630 included in the Test Year sales expenses include costs associated with the Company's
631 attempts to expand its competitive wholesale business. [REDACTED]

632 On Attachment 5 of the November 30, 1999 synergies report for Power Operations, Power
633 Trading and Term Marketing (OPC 010182), the Company indicated that [REDACTED]

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

636
637 A: Although it appears that the Power Marketing expenses may include expenses related to
638 expansion of FPC's non-regulated wholesale sales, I do not have sufficient information to
639 verify this or to provide a breakdown the Power Marketing expenses of \$4.897 million into
640 the various services provided by this department; therefore, I am limiting my adjustment to
641 an allocated share of the Power Marketing expenses to the shareholders, to the extent of the
642 opportunity for the sharing of margins, and to the wholesale average rate customers. Since
643 gains from sales are credited to the customers based on a three year moving average, I would
644 propose to allocate 20% of the increase in 2002 Power Marketing expenses over the three
645 year average from 1999 through 2001. Based on the information provided in Schedule C-12,
646 page 8 of 13, the average Power Marketing expenses over 1999 through 2001 were \$2.512
647 million. The 2002 increase over the three year average is thus \$2.385 million. Allocating
648 20% of the \$2.385 million to the shareholders provides a reduction in the total system
649 revenue requirement of \$477,000. The remainder of the Test Year Power Marketing expense
650 of \$4.420 million would then be allocated to both the wholesale and retail jurisdictions,
651 excluding stratified wholesale sales, which have specifically defined fuel costs. Based on

652 FPC's energy allocator for average rate sales, Factor K306, 97.646%, or \$4.316 million, of
653 the total costs would be borne by the retail customers. This adjustment reduces the retail
654 customers' revenue requirement by \$581,000.

655 **LAST CORE NUCLEAR FUEL AND END-OF-LIFE MATERIALS AND SUPPLIES**

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

658

659 A: The Company is proposing to amortize the last core of nuclear fuel in the Crystal River 3
660 nuclear unit over the 15-year remaining life of the plant. The cost to the retail customers is
661 \$1.172 million a year. The Commission addressed this issue in Order PSC-02-0055-PAA-EI
662 and concluded that the associated costs should be considered a base rate future obligation and
663 recommended the amortization of the Last Core costs as a base rate fuel expense with a
664 credit to an unfunded Account 228 reserve.

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

667

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

677 In the May 2001 National Energy Policy, the National Energy Policy Development Group
678 (“NEPD Group”) noted that:

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

684
685 The NEPD Group, went on to recommend that the President support the expansion of nuclear
686 energy in the United States and made a specific recommendation to:

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

689
690 On December 4, 2001, Dr. Richard A. Meserve, Chairman of the Nuclear Regulatory
691 Commission (“NRC”), spoke at the Energy Investor Policy and Regulation Conference
692 regarding the nuclear power industry. When addressing nuclear plant license extensions, Dr.
693 Meserve explained:

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

704
705 Given FPC’s expectation of filing for a license extension and the National Energy Policy and
706 NRC’s expressed support of such extensions, it appears likely that the CR3 license will be
707 extended to 2036. Beginning amortization at this time thus appears premature.

708 In his comments, Dr. Meserve also noted that the NRC set a 30-month schedule for review of

709 license renewal applications and had been able to meet or beat that timetable in each case
710 without sacrificing quality. Thus, even if FPC waited until the fourth quarter of 2005 to
711 apply for license extension, the extension could be expected sometime in 2008, leaving 8
712 years to amortize the last core if the extension is rejected, and a full 28 years to amortize the
713 last core if a 20 year extension is granted. Elimination of the Last Core amortization in this
714 proceeding would decrease the retail customers' revenue requirement by \$1.172 million.
715 If the Commission chooses to allow FPC to begin amortization at this time, based on the
716 decision set forth in Order PSC-02-0055-PAA-EI, then, at a minimum, the Commission
717 should reconsider the length of the amortization period. Recognizing the probability of
718 license extension, the amortization could be extended over a 35-year period. As directed by
719 the Commission, FPC could then address required modifications to the amortization in its
720 future decommissioning studies, thus allowing for increasing the amortization in the event
721 that license extension is not granted. To amortize the Last Core over a 35-year period, I have
722 followed the Company's methodology which was set forth in its response to Citizens'
723 Interrogatory No. 61. I escalated the cost of the Last Core for an additional 20 years,
724 resulting in a future Last Core cost of \$26.911 million. Amortization of this level of Last
725 Core cost over a 35-year period would be \$769,000. The rate base offset for the Account 228
726 balance, net of accumulated deferred income taxes, would be decreased to reflect the lower
727 amortization. The combined effect of this adjustment would be a reduction in total system
728 revenue requirements of \$412,000. The reduction in the retail customers' revenue
729 requirement would be \$402,000.

730

731
732 Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR AMORTIZING THE
733 NUCLEAR END-OF-LIFE MATERIALS AND SUPPLIES BALANCE.

734
735 A: As with the Last Core amortization, the Company is proposing to amortize the projected
736 balance of materials and supplies that will be on-hand at the end of the CR3 license life.
737 FPC originally estimated this amount to be \$25 million and thus included \$1.667 million in
738 amortization over the 15 year period. Subsequently, FPC reduced this amount to \$22
739 million, with an annual amortization of \$1.467 million. This reduction has not been reflected
740 in FPC's Schedule E cost of service studies.

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

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

751 Again, as an alternative, the materials and supplies should be amortized over a 35-year
752 period. Since the materials and supplies are already in inventory, there would be no
753 escalation in value over the remaining life; therefore, the amortization would be reduced to
754 \$628,571. In addition, the rate base offset for Account 228, net of accumulated deferred

755 income taxes, would be decreased. The combined effect of this adjustment would be a
756 decrease in the total system revenue requirement of \$801,000 (assuming the original
757 overstatement is already corrected) and the retail customers' revenue requirement of
758 \$769,000.

759 **TRANSMISSION OPERATING AND MAINTENANCE EXPENSES**

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

762
763 A: The Company is projecting total transmission expenses of \$34.288 million for the Test Year,
764 after reflection of \$1.5 million in estimated merger-related synergies. This is an annual
765 increase of 6.8% a year including the estimated merger-related synergies and 9.1% a year if
766 those synergies are not included. In 1999 and 2000, the Company had expenses of \$9.7
767 million and \$5.4 million for Account 565, Transmission of Electricity by Others. This
768 expense is not expected to continue in 2002 due to termination of the Seminole Electric
769 wholesale contract in December, 2001. If these amounts are removed from the 1999 and
770 2000 expenses, the annual rate of increase to the Company's projected Test Year
771 Transmission expenses is 13.2% and 17.9%, respectively. Before the estimated offsets for
772 merger-related synergies, the annual rate of increase would be 14.8% based on 1999
773 expenses and 20.5% based on 2000 expenses.

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

776
777 A: As explained by FPC's Witness Rogers:

778the time has come when we must replace deteriorating poles, cross
779 arms, insulators, and other aging facilities because the Company's
780 transmission facilities are the arteries of the utility's electric service

781 system. Therefore, we are budgeting expenditures for 2002 that are
782 reasonably necessary to maintain this system in good working order in
783 future years...we have identified a number of areas where we must
784 replace or repair transmission equipment to be prepared fully to meet
785 the demands of the new millennium. But more than that, we are
786 committed to providing proactive maintenance of substation equipment
787 and other facilities to ensure continuing reliability in future years.
788 (Rogers, page 4)

789
790 Witness Rogers goes on to explain FPC's reliability initiatives, including the need to repair
791 or replace some of the substation breakers, defective substation equipment, poles and other
792 equipment, and that FPC is committed to accomplishing the needed repairs and replacement
793 over a three-year time period. Exhibit SSR-1 sets forth a summary of FPC's planned
794 reliability initiatives and the operating and maintenance expenses and capital costs associated
795 with those initiatives over the three-year time period, beginning with the Test Year. As
796 shown on Exhibit SSR-1, the Company is projecting \$9.73 million in operating and
797 maintenance expenses for reliability initiatives during the Test Year. This \$9.73 million
798 would fully explain the large increases in Transmission expenses from 2000 to 2002;
799 however, given the Company's reduction in employees, any portion of the \$9.73 million
800 related to labor costs would not be incremental costs, but would simply be shifting the
801 responsibilities of employees whose costs were already included in the 2000 transmission
802 expenses.

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

805
806 A: Yes. Table 7 below shows a breakdown of the Test Year operating and maintenance
807 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

808

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

811 While these repairs and upgrades may be necessary or desirable, it is clear that such
812 initiatives are planned to increase reliability, not just for the immediate three-year period, but
813 far into the future. Witness Rogers testified that FPC's system was installed in the 1950s,
814 1960s, and 1970s and that it is now showing signs of age. Thus it has served the customers
815 for 30 to 50 years. These reliability improvements will obviously provide benefits for years
816 to come. In addition, it is likely that a regional transmission organization ("RTO") will be
817 formed and, at this time, the method of cost recovery under such an RTO and resulting
818 impact on the retail customers is not known. Further, it appears that many of these initiatives
819 are playing "catch up" for maintenance that could have been done on a proactive basis,
820 perhaps at lower costs. Witness Rogers notes that this plan will enable the Company to focus
821 on preventive maintenance, rather than merely reactive maintenance. For all of these
822 reasons, I believe the costs of the reliability initiatives should be either capitalized as a
823 component of the associated capital costs or amortized over a longer period of time.

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

826

827 A: Yes. Although many of these initiatives are related to capital improvements that will
828 depreciated over a much longer life, I have limited the amortization to a 10 year period.

829 Based on the expected total expenditures of \$29.19 million over the three-year period, the

830 annual amortization of the total reliability initiatives would be \$2.919 million. In the Test

831 Year, this would result in deferral of \$6.811 million for collection in later years; therefore, I

832 would increase rate base by the average Test Year deferral of \$3.406 million, net of deferred

833 income taxes of \$1.314 million. The net impact of this adjustment is a decrease of \$6.51

834 million in the total system revenue requirement and \$4.727 million in the retail customers'

835 revenue requirement.

836 **TIGER BAY ACCELERATED AMORTIZATION**

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

838 A: In Order No. PSC-97-0652-S-EQ, the Commission approved a stipulation allowing FPC to

839 recover its costs of acquiring the Tiger Bay cogeneration facility. The first \$75 million of the

840 costs were placed in rate base, to be depreciated. The remainder of the purchase price was

841 treated as a Regulatory Asset. The Commission approved a methodology of amortizing the

842 Tiger Bay Regulatory Asset by the difference between the continuation of charges that would

843 have been otherwise incurred through purchased power adjustments if the facility had not

844 been purchased, net of actual fuel charges incurred. At that time, FPC projected that the

845 asset would be fully amortized by January, 2008, using this methodology. The Commission

846 also allowed FPC to accelerate the amortization of the Tiger Bay Regulatory Asset on a

847 discretionary basis from its earnings.

848 Subsequent to Order No. PSC-97-0652-S-EQ, FPC's earnings were excessive and the
849 Commission approved FPC's application of excess earnings to the accelerated amortization
850 of the Tiger Bay Regulatory Asset. Accelerated amortization included \$14 million in 1998,
851 \$10.3 million in 1999, \$48.5 million in 2000, and \$63 million in 2001. In addition, as
852 explained by Witness Javier Portuondo on page 5 of his testimony, the Company is
853 projecting additional accelerated amortization of \$30 million for 2001 and \$9 million for
854 2002 during the pendency of the rate case. Witness Portuondo argued that the amount of
855 funds subject to refund should be reduced by the additional accelerated amortization of \$39
856 million. The Commission subsequently addressed this issue in Order No. PSC-01-2313-
857 PSC-EI and indicated that the refund would be reduced by the actual amount of additional
858 accelerated amortization taken during the refund effective period.

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

861 A: The Company is projecting amortization of \$40,666,149 through the purchased power
862 collections, less fuel costs, in the Test Year. In addition, the Company has included
863 accelerated amortization of \$9 million in the Test Year revenue requirement.
864

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

868 A: No. Order No. PSC-7-0652-S-EQ provided for the Company to apply its earnings to
869 accelerated amortization on a discretionary basis. It did not, however, allow the Company to
870 convert such "excess earnings" to "required earnings" in the development of base rates.
871

872 Even if the Company projects excess earnings during the refund effective period and projects
873 that an additional \$9 million will be applied to the Tiger Bay Regulatory Asset amortization
874 during that time, the Company will be allowed to reduce any refunds by the additional
875 amortization. The additional amortization should not be used in setting rates to be applied
876 prospectively.

877 In addition, as noted by the Commission in Order No. PSC-7-0652-S-EQ, the advantages of
878 the Stipulation are eroded in this proceeding by the additional revenue requirement
879 associated with the portion of the Tiger Bay cost that is included in rate base. Since the time
880 of Order No. PSC-7-0652-S-EQ, FPC has apparently made additions to the Tiger Bay
881 facility, resulting in a December, 2001 balance of \$97.1 million. Five million dollars in
882 further additions are planned in 2002. The Tiger Bay depreciation expense included in the
883 Test Year revenue requirement is \$5.8 million.

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

886
887 A: Since the Tiger Bay Regulatory Asset is not in rate base, the customers will benefit more by
888 reducing *current* revenue requirements and extending the amortization period. Given the
889 Company's projected \$40 million amortization through the purchased power collections, net
890 of fuel costs, the elimination of the \$9 million accelerated amortization adjustment would
891 only extend the time period for the continued collection of the Tiger Bay purchased power
892 costs through the fuel adjustment clause by a few months, with full amortization occurring
893 sometime in 2004. This cost would be automatically eliminated through the fuel adjustment
894 clause, rather than requiring a base rate adjustment at that time.

895 **RATE CASE EXPENSES**

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

898
899 A: The Company has estimated total costs associated with the current case of \$1.644 million and
900 is proposing to amortize those costs over a two-year period.

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

903
904 A: Yes. A portion of these costs were incurred in 2001. If these costs are excluded from the
905 2001 Surveillance Report, FPC's earnings will increase and FPC will then have the
906 discretion as to whether, and to what amount, to include any such increase as additional
907 amortization on Tiger Bay. FPC is already projecting additional Tiger Bay amortization for
908 2001, indicating expected excess earnings. If the Commission is interested in increasing the
909 Tiger Bay amortization for 2001, then FPC should only be allowed to exclude the rate case
910 expenses from 2001 to the extent that such amounts are applied to the Tiger Bay
911 amortization. Otherwise, FPC should be required to absorb the 2001 rate case expenses and
912 amortize only the remainder of the expenses that are expected to be incurred in 2002.

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

915
916 A: No. The 2001 rate case expenses should be verified as part of this proceeding or as part of
917 the Surveillance Report.

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

920
921 A: In the last FPC rate case, the Commission required FPC to amortize its rate case expenses
922 over a 4 year period, since rates were expected to be in effect for at least that period of time.

923 Given the length of time that has actually expired between the last rate case and the current
924 proceeding, it would be appropriate to again allow the amortization over a 4 year period.

925 Q: PLEASE DESCRIBE THE ALTERNATIVE METHODOLOGIES YOU ARE
926 PROPOSING.

927
928 A: For purposes of demonstration, assuming that one-half of the estimated expenses were
929 incurred in 2001, the expenses would either i) be recognized in the 2001 Surveillance Report
930 and absorbed by FPC, with the balance of \$822,000 amortized over 4 years at \$205,500 a
931 year, thereby reducing the retail customers' revenue requirement by \$616,500 or ii) be
932 removed from 2001 expenses, increasing the excess revenues that would be applied to the
933 Tiger Bay accelerated amortization and allowing the total rate case expenses of \$1.6 million
934 to be amortized over 4 years at \$411,000 a year.

935 **COST ALLOCATION**

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

942
943 A: Witness Slusser explains that energy utilization is a major consideration in the type of plants
944 considered to be built. Base load plants are typically more capital intensive, but the higher
945 capital costs are typically justified by the lower energy costs and higher expected energy
946 utilization.

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

949
950 A: Yes. Witness Slusser has also proposed adjusting the allocation of capacity costs in both the

951 Capacity Cost Recovery Clause and the Energy Conservation Cost Recovery Clause.

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

954
955 A: No. While Witness Slusser is correct in his contention that a portion of FPC's production
956 facilities were constructed to provide low-cost energy, the proposed allocation will only
957 address half of the issue. Since high load factor customers have a better utilization of energy
958 relative to the demands placed on the system, Witness Slusser's recommended change in
959 allocation methodology would shift costs to the high load factor customers. Under the fuel
960 adjustment practices, FPC's customers pay for their energy based on average system costs.
961 Since a greater portion of high load factor customers' energy requirements come from base
962 energy, the high load factor customers are, in effect, subsidizing the low load factor
963 customers through the fuel adjustment charges. To change the allocation methodology for
964 production plant without changing the corresponding allocation of fuel costs would unfairly
965 penalize the high load factor customers.

966 **ALLOCATED COST OF SERVICE AND RECOMMENDED REVENUE REQUIREMENTS**

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

969
970 A: Yes. Exhibit SLB-3 is a copy of the cost of service model I developed to evaluate the
971 Company's Test Year revenue requirements. This model was developed to reflect the Total
972 System allocations, as well as the retail jurisdiction revenue requirement and allocations
973 under the Company's 75% Demand/25% Energy cost allocation case, which they have
974 treated as their "Base Case".

975

976 Q: DOES EXHIBIT SLB-3 REFLECT THE MODIFICATIONS REQUESTED BY WITNESS
977 MYERS IN HIS NOVEMBER 15, 2001 TESTIMONY?
978

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

986 Q: HAVE YOU DEVELOPED A REVISED COST OF SERVICE STUDY REFLECTING
987 ALL THE ADJUSTMENTS YOU HAVE RECOMMENDED HEREIN?
988

989 A: Yes. Exhibit SLB-4 is a copy of the revised cost of service study. Table 8 below
990 summarizes Exhibit SLB-4 and shows the breakdown of the revenue requirements and rate
991 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%)
Curtable	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%)

992

993 Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

994 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"

***Papers and
Publications***

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

"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

Distribution O&M
(Thousands \$)

	1996	1997	1998	1999	2000	2002
580 Supervision & Engineering	2,833	3,389	5,083	4,688	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
585.02 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	1,468
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	97,168

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]			1,956
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
<u>Demand Factors</u>								
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%
<u>Energy Factors</u>								
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%
<u>Distribution</u>								
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		100,000	100,000	77,150	5,310	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		100,000	100,000	88,785	7,222	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		101,149.053	100,000	79,132	7,173	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		100,000	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		100,000	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		100,000	100,000	0	0	0	0
3.14	Ratio To Total Electric		100.00%	100.00%	0.00%	0.00%	0.00%	0.00%
<u>Customer Factors</u>								
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		100,001	100,000	88,129	7,141	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	6,911	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.		Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Demand Factors</u>								
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%
<u>Energy Factors</u>								
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%
<u>Distribution</u>								
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%
<u>Customer Factors</u>								
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%

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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%
	<u>Wages And Salaries</u>							
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	<u>Customer Serv & Info. Sales</u>	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	<u>Administrative & General</u>	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.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Gross Electric Plant In Service</u>								
<u>Production Plant</u>								
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%
<u>Transmission Plant</u>								
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%
<u>Distribution Plant</u>								
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%
<u>General & Intangible Plant</u>								
20.01	Labor Related	8.17	340,041	321,164	206,192	12,975	808	81,124
20.02	Retail Customer Related (Ccs)	4.02	57,976	57,976	51,094	4,140	410	1,877
20.03	General Plant In Service	SUM	398,017	379,140	257,286	17,116	1,218	83,001
20.04								
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%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailed Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Gross Electric Plant In Service</u>								
<u>Production Plant</u>								
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%
<u>Transmission Plant</u>								
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%
<u>Distribution Plant</u>								
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%
<u>General & Intangible Plant</u>								
20.01	Labor Related	8.17	871	11,115	1,622	4,024	2,431	18,877
20.02	Retail Customer Related (Crs)	4.02	0	6	449	0	0	0
20.03	General Plant In Service	SUM	871	11,121	2,071	4,024	2,431	18,877
20.04								
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%

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
<u>Depreciation</u>								
<u>Production Plant</u>								
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 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	1,114,844	55,434	2,834	604,618
<u>Transmission Plant</u>								
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
<u>Distribution Plant</u>								
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
<u>General & Intangible Plant</u>								
24.01	Labor ed	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
<u>Common & Other Plant</u>								
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.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Accumulated Depreciation</u>								
<u>Production Plant</u>								
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
<u>Transmission Plant</u>								
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
<u>Distribution Plant</u>								
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
<u>General & Intangible Plant</u>								
24.01	Labor 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
<u>Common & Other Plant</u>								
25.01	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.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Net Electric Plant</u>								
<u>Production Plant</u>								
26.01	Production In Service	PULL	3,462,260	3,162,426	1,878,734	93,418	4,775	1,018,902
26.02	Total Prod Deprec Reserv	PULL	<u>-2,053,606</u>	<u>-1,876,589</u>	<u>-1,114,844</u>	<u>-55,434</u>	<u>-2,834</u>	<u>-604,618</u>
26.03	Net Production	SUM	1,408,654	1,285,837	763,890	37,984	1,942	414,284
<u>Transmission Plant</u>								
27.01	Transmission In Service	PULL	960,641	697,438	434,363	20,115	933	210,527
27.02	Total Trans Deprec Reserve	PULL	<u>-438,036</u>	<u>-317,459</u>	<u>-197,819</u>	<u>-9,153</u>	<u>-424</u>	<u>-95,752</u>
27.03	Net Transmission Plant	SUM	522,605	379,980	236,544	10,962	509	114,776
<u>Distribution Plant</u>								
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	<u>-1,043,696</u>	<u>-1,041,053</u>	<u>-681,657</u>	<u>-45,813</u>	<u>-1,779</u>	<u>-187,109</u>
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
<u>General & Intangible Plant</u>								
30.01	General Plant In Ser	PULL	398,017	379,140	257,286	17,116	1,218	83,001
30.02	Deprec	PULL	<u>-182,507</u>	<u>-174,695</u>	<u>-122,154</u>	<u>-8,354</u>	<u>-630</u>	<u>-34,926</u>
30.03	Net General & Intang Plant	SUM	215,510	204,445	135,132	8,762	588	48,075
<u>Common & Other Plant</u>								
31.01	Total Com & Other 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
<u>Net Electric Plant</u>								
<u>Production Plant</u>								
26.01	Production Plant In Service	PULL	10,057	148,349	8,191	0	0	299,834
26.02	Total Prod Deprec Reserv	PULL	<u>-5,968</u>	<u>-88,031</u>	<u>-4,860</u>	<u>0</u>	<u>0</u>	<u>-177,017</u>
26.03	Net Production Plant	SUM	4,089	60,319	3,330	0	0	122,817
<u>Transmission Plant</u>								
27.01	Transmission Plant In Service	PULL	1,844	28,938	718	0	0	263,203
27.02	Total Trans Deprec Reserve	PULL	<u>-837</u>	<u>-13,152</u>	<u>-321</u>	<u>0</u>	<u>0</u>	<u>-120,577</u>
27.03	Net Transmission Plant	SUM	1,007	15,786	397	0	0	142,625
<u>Distribution Plant</u>								
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	<u>-2,064</u>	<u>-15,787</u>	<u>-4,733</u>	<u>-65,524</u>	<u>-36,587</u>	<u>-2,643</u>
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
<u>General & Intangible Plant</u>								
30.01	General Plant In Service	PULL	871	11,121	2,071	4,024	2,431	18,877
30.02	Deprec	PULL	<u>-361</u>	<u>-4,604</u>	<u>-995</u>	<u>-1,666</u>	<u>-1,006</u>	<u>-7,812</u>
30.03	Net General & Intang Plant	SUM	511	6,517	1,076	2,359	1,425	11,065
<u>Common & Other Plant</u>								
31.01	Total Com & Other Plant	PULL	<u>-12</u>	<u>-153</u>	<u>-15</u>	<u>-84</u>	<u>-51</u>	<u>-390</u>
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
<u>O & M Expenses</u>								
<u>Production O & M</u>								
<u>Energy Related Prod O & M</u>								
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	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
<u>Demand Related Prod O & M</u>								
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 - 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
<u>Transmission O & M</u>								
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
<u>Distribution O & M</u>								
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.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>O & M Expenses</u>								
<u>Production O & M</u>								
<u>Energy Related Prod O & M</u>								
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	<u>Total Energy Related</u>	SUM	397	5,249	617	0	0	7,456
<u>Demand Related Prod O & M</u>								
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 F-Nuclear M&S Inventory	1.02	5	75	4	0	0	67
33.07	<u>Total Demand Related</u>	SUM	391	5,775	353	0	0	23,415
33.07	<u>Total Production O & M</u>	SUM	788	11,024	970	0	0	30,871
<u>Transmission O & M</u>								
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	<u>Total Transmission O & M</u>	SUM	66	1,033	26	0	0	9,393
<u>Distribution O & M</u>								
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	<u>Total Distribution O & M</u>	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
<u>Customer Accounting</u>								
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 Comp	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
<u>Administrative & General Expenses</u>								
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	<u>Ratio</u>		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.	Allocators	Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Customer Accounting</u>								
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 Comp	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
<u>Administrative & General Expenses</u>								
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	<u>Ratio</u>		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
<u>Rate Base Adjustments</u>								
<u>Additive Adjustments</u>								
<u>Plant Held For Future Use</u>								
41.01	Transmission	1.08	6,602	4,761	2,971	137	6	1,433
41.02	Distribution	3.02	<u>1,673</u>	<u>1,665</u>	<u>1,062</u>	<u>60</u>	<u>2</u>	<u>467</u>
41.03	Total Land Held For Future Use	SUM	8,275	6,426	4,033	197	8	1,900
<u>Construction Work In Progress</u>								
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	<u>-66,597</u>	<u>-60,830</u>	<u>-36,138</u>	<u>-1,797</u>	<u>-92</u>	<u>-19,599</u>
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
<u>Working Capital</u>								
<u>Materials And Supplies</u>								
<u>Fuel Supplies</u>								
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	<u>-369</u>	<u>-360</u>	<u>-182</u>	<u>-11</u>	<u>-1</u>	<u>-139</u>
44.04	Total Fuel Stocks	SUM	139,589	125,730	63,383	3,989	262	48,509
<u>Plant Materials & Supplies</u>								
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	<u>-512</u>	<u>-472</u>	<u>-297</u>	<u>-17</u>	<u>-1</u>	<u>-124</u>
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
<u>Miscellaneous Working Capital</u>								
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	20.06	<u>8,995</u>	<u>8,285</u>	<u>5,224</u>	<u>300</u>	<u>14</u>	<u>2,173</u>
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
<u>Preliminary Summary</u>								
49.01	Total Additive Adjustments		91,150	78,953	49,272	2,658	125	22,076
49.02	Total Working Capital		<u>149,743</u>	<u>124,765</u>	<u>57,095</u>	<u>2,317</u>	<u>-45</u>	<u>53,406</u>
49.03	Total Rate Base Adjustments		240,893	203,719	106,367	4,976	79	75,481
<u>Rate Base Calculation</u>								
49.04	Net Electric Plant In Service		3,742,339	3,461,777	2,216,526	129,991	5,959	879,926
49.05	Adjustments		<u>240,893</u>	<u>203,719</u>	<u>106,367</u>	<u>4,976</u>	<u>79</u>	<u>75,481</u>
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%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Rate Base Adjustments</u>								
<u>Additive Adjustments</u>								
<u>Plant Held For Future Use</u>								
41.01	Transmission	1.08	12	196	5	0	0	1,841
41.02	Distribution	3.02	<u>8</u>	<u>55</u>	<u>12</u>	<u>0</u>	<u>0</u>	<u>8</u>
41.03	Total Land Held For Future Use	SUM	20	251	17	0	0	1,849
<u>Construction Work In Progress</u>								
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 Afid Cwip Prod	16.06	<u>-193</u>	<u>-2,854</u>	<u>-158</u>	<u>0</u>	<u>0</u>	<u>-5,767</u>
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
<u>Working Capital</u>								
<u>Materials And Supplies</u>								
<u>Fuel Supplies</u>								
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
<u>Plant Materials & Supplies</u>								
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
<u>Miscellaneous Working Capital</u>								
47.01	OPEB - D.A. Retail	8.18	-371	-4,731	-690	-1,713	-1,035	0
47.02	OPEB - DA Wholesale	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	20.06	<u>22</u>	<u>278</u>	<u>28</u>	<u>153</u>	<u>92</u>	<u>710</u>
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
<u>Preliminary Summary</u>								
49.01	Total Additive Adjustments		220	2,933	226	900	544	12,197
49.02	Total Working Capital		<u>608</u>	<u>7,959</u>	<u>392</u>	<u>1,899</u>	<u>1,134</u>	<u>24,978</u>
49.03	Total Rate Base Adjustments		828	10,892	618	2,799	1,678	37,174
<u>Rate Base Calculation</u>								
49.04	Net Electric Plant In Service		9,166	109,039	12,483	59,654	39,034	280,562
49.05	Adjustments		<u>828</u>	<u>10,892</u>	<u>618</u>	<u>2,799</u>	<u>1,678</u>	<u>37,174</u>
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
	<u>Revenue Credits</u>							
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	<u>147</u>	<u>147</u>	<u>130</u>	<u>10</u>	<u>1</u>	<u>5</u>
52.10	Total Revenue Credits	SUM	39,039	37,556	26,825	1,795	104	7,542
53.01	<u>Total Present Revenues</u>	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%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtable 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
	<u>Revenue Credits</u>							
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	Customer Accounting	4.06	0	0	1	0	0	0
52.10	Total Revenue Credits	SUM	77	813	140	159	102	1,483
53.01	<u>Total Present Revenues</u>	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	<u>9,000</u>	<u>9,000</u>	<u>5,347</u>	<u>266</u>	<u>14</u>	<u>2,900</u>
54.07	Total Production Deprec 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	Transmission	1.08	<u>28,831</u>	<u>20,791</u>	<u>12,976</u>	<u>599</u>	<u>28</u>	<u>6,257</u>
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	Equipment	3.14	<u>90</u>	<u>90</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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	16,099	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 Sebring	8.17	<u>-2,208</u>	<u>-2,085</u>	<u>-1,339</u>	<u>-84</u>	<u>-5</u>	<u>-527</u>
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%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Depreciation Expense</u>								
<u>Production Depreciation</u>								
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	<u>29</u>	<u>422</u>	<u>23</u>	<u>0</u>	<u>0</u>	<u>0</u>
54.07	Total Production Deprec Exp		528	7,782	430	0	0	14,176
<u>Transmission Depreciation</u>								
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	<u>54</u>	<u>858</u>	<u>20</u>	<u>0</u>	<u>0</u>	<u>8,040</u>
55.05	Total Trans Deprec Exp	SUM	57	899	22	0	0	8,189
<u>Distribution Depreciation</u>								
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	<u>0</u>	<u>90</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
56.08	Total Dist Deprec Expense	SUM	195	1,499	462	10,166	4,386	249
<u>General & Intang Depreciation</u>								
57.01	Labor Related	8.17	68	868	127	314	190	1,474
57.02	Retail Customer Related (Ccs)	4.02	0	1	45	0	0	0
57.03	Adj S - Sebring	8.17	<u>-6</u>	<u>-72</u>	<u>-11</u>	<u>-26</u>	<u>-16</u>	<u>-123</u>
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	23,966

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
<u>Taxes Other Than Inc & Rev</u>								
<u>Real Estate & Property Tax</u>								
59.01	Amount Allocable	20.06	85,272	78,544	49,527	2,843	133	20,601
59.02	DA Wholesale	10.10	<u>102</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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
<u>Other Taxes & Misc Expenses</u>								
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 M - Exclude Franchise, Grt	9.03	<u>-138,166</u>	<u>-138,166</u>	<u>-87,709</u>	<u>-6,108</u>	<u>-251</u>	<u>-35,597</u>
62.04	Misc Allowable Expenses	SUM	-938	-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.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Taxes Other Than Inc & Rev</u>								
<u>Real Estate & Property Tax</u>								
59.01	Amount Allocable	20.06	210	2,636	267	1,450	876	6,728
59.02	DA Wholesale	10.10	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>102</u>
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
<u>Other Taxes & Misc Expenses</u>								
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	<u>-407</u>	<u>-4,384</u>	<u>-522</u>	<u>-2,168</u>	<u>-1,018</u>	<u>0</u>
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
<u>Tax Calculations</u>								
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	<u>-98,595</u>	<u>-91,128</u>	<u>-57,620</u>	<u>-3,363</u>	<u>-165</u>	<u>-23,768</u>
63.05	Net Income Before Taxes	SUM	552,029	516,881	329,711	27,857	550	135,826
63.06	Less Interest Synchronization	CALC	-101,592	-93,488	-59,245	-3,442	-154	-24,368
63.07	Additions & Deductions	20.06	<u>95,492</u>	<u>87,958</u>	<u>55,463</u>	<u>3,184</u>	<u>149</u>	<u>23,070</u>
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%

EXHIBIT SLB-3

Line No.	Allocators	Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Tax Calculations</u>								
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	<u>-245</u>	<u>-3,071</u>	<u>-333</u>	<u>-1,600</u>	<u>-965</u>	<u>-7,467</u>
63.05	Net Income Before Taxes	SUM	1,754	13,962	1,418	4,382	1,421	35,148
63.06	Less Interest Synchronization	CALC	-255	-3,059	-334	-1,593	-1,038	-8,104
63.07	Additions & Deductions	20.06	<u>235</u>	<u>2,952</u>	<u>299</u>	<u>1,624</u>	<u>981</u>	<u>7,534</u>
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	<u>-167,250</u>	<u>-157,331</u>	<u>-100,553</u>	<u>-9,201</u>	<u>-143</u>	<u>-41,423</u>
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.	Curtaillable 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	<u>-562</u>	<u>-4,005</u>	<u>-398</u>	<u>-965</u>	<u>-81</u>	<u>-9,919</u>
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.		Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Demand Factors</u>								
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%
<u>Energy Factors</u>								
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%
<u>Distribution</u>								
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%
<u>Customer Factors</u>								
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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Demand Factors</u>								
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%
<u>Energy Factors</u>								
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%
<u>Distribution</u>								
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%
<u>Customer Factors</u>								
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%

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FLORIDA POWER CORPORATION
 ALLOCATED COST OF SERVICE STUDY
 PROJECTED 2002 TEST YEAR
 PUBLIX ADJ CASE I2CP 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
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%
	<u>Wages And Salaries</u>							
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	<u>Customer Serv & Info. Sales</u>	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	<u>Administrative & General</u>	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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Gross Electric Plant In Service</u>								
<u>Production Plant</u>								
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%
<u>Transmission Plant</u>								
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%
<u>Distribution Plant</u>								
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%
<u>General & Intangible Plant</u>								
20.01	Labor Related	8.17	340,041	321,164	208,383	12,922	795	79,574
20.02	Retail Customer Related (Css)	4.02	57,976	57,976	51,094	4,140	410	1,877
20.03	General Plant In Service	SUM	398,017	379,140	259,477	17,062	1,205	81,451
20.04								
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
 PUBLIC ADJ CASE 12CP AND 1/13TH AD

EXHIBIT SLB-4

Line No.		Alloc.	Curtable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Production Plant</u>								
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%
<u>Transmission Plant</u>								
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%
<u>Distribution Plant</u>								
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%
<u>General & Intangible Plant</u>								
20.01	Labor Related	8.17	830	10,701	1,503	4,024	2,431	18,877
20.02	Retail Customer Related (Css)	4.02	0	6	449	0	0	0
20.03	General Plant In Service	SUM	830	10,707	1,952	4,024	2,431	18,877
20.04								
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.	Allocators	Alloc.	Total Electric	FPSC Jurisdiction	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Accumulated Depreciation</u>								
<u>Production Plant</u>								
21.01	Base	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
<u>Transmission Plant</u>								
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
<u>Distribution Plant</u>								
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
<u>General & Intangible Plant</u>								
24.01	Labor Related	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
<u>Common & Other Plant</u>								
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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Accumulated Depreciation</u>								
<u>Production Plant</u>								
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
<u>Transmission Plant</u>								
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
<u>Distribution Plant</u>								
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
<u>General & Intangible Plant</u>								
24.01	Labor ated	8.17	343	4,429	622	1,666	1,006	7,812
24.02	(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
<u>Common & Other Plant</u>								
25.01	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	Residential	Gen Serv. Non Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Production Plant</u>								
26.01	Produ t In Service	PULL	3,462,260	3,162,426	1,944,449	91,805	4,396	972,414
26.02	Deprec	PULL	<u>-2,053,606</u>	<u>-1,876,589</u>	<u>-1,153,839</u>	<u>-54,477</u>	<u>-2,608</u>	<u>-577,032</u>
26.03	Net Production Plant	SUM	1,408,654	1,285,837	790,610	37,328	1,787	395,382
<u>Transmission Plant</u>								
27.01	Transmissic t In Service	PULL	960,641	697,438	434,982	20,100	929	210,089
27.02	Total Trans Deprec Reserve	PULL	<u>-438,036</u>	<u>-317,459</u>	<u>-198,027</u>	<u>-9,148</u>	<u>-423</u>	<u>-95,605</u>
27.03	Net Transmission Plant	SUM	522,605	379,980	236,955	10,952	507	114,484
<u>Distribution Plant</u>								
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	<u>-1,043,696</u>	<u>-1,041,053</u>	<u>-681,657</u>	<u>-45,813</u>	<u>-1,779</u>	<u>-187,109</u>
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
<u>Genera & Intangible Plant</u>								
30.01	Gener	PULL	398,017	379,140	259,477	17,062	1,205	81,451
30.02	Deprec	PULL	<u>-182,507</u>	<u>-174,695</u>	<u>-123,061</u>	<u>-8,331</u>	<u>-625</u>	<u>-34,284</u>
30.03	Net General & Intang Plant	SUM	215,510	204,445	136,416	8,731	581	47,166
<u>Common & Other Plant</u>								
31.01	Total Com & Other Plant	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.	Curtaillable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Net Electric Plant</u>								
<u>Production Plant</u>								
26.01	Production In Service	PULL	8,823	135,921	4,617	0	0	299,834
26.02	Total Prod Deprec Reserve	PULL	<u>-5,236</u>	<u>-80,656</u>	<u>-2,740</u>	<u>0</u>	<u>0</u>	<u>-177,017</u>
26.03	Net Production Plant	SUM	3,587	55,265	1,877	0	0	122,817
<u>Transmission Plant</u>								
27.01	Transmission In Service	PULL	1,832	28,821	684	0	0	263,203
27.02	Total Trans Deprec Reserve	PULL	<u>-833</u>	<u>-13,112</u>	<u>-310</u>	<u>0</u>	<u>0</u>	<u>-120,577</u>
27.03	Net Transmission Plant	SUM	999	15,708	375	0	0	142,625
<u>Distribution Plant</u>								
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	<u>-2,064</u>	<u>-15,787</u>	<u>-4,733</u>	<u>-65,524</u>	<u>-36,587</u>	<u>-2,643</u>
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
<u>General & Intangible Plant</u>								
30.01	General Plant In Service	PULL	830	10,707	1,952	4,024	2,431	18,877
30.02	Deprec	PULL	<u>-344</u>	<u>-4,433</u>	<u>-946</u>	<u>-1,666</u>	<u>-1,006</u>	<u>-7,812</u>
30.03	Net General & Intang Plant	SUM	486	6,274	1,007	2,359	1,425	11,065
<u>Common & Other Plant</u>								
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
 PUBLIC 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
<u>O & M Expenses</u>								
<u>Production O & M</u>								
<u>Energy Related Prod O & M</u>								
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	<u>Total Energy Related</u>	SUM	88,387	80,959	40,813	2,569	168	31,236
<u>Demand Related Prod O & M</u>								
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	<u>Total Demand Related</u>	SUM	149,249	125,902	78,587	3,842	200	37,500
33.07	<u>Total Production O & M</u>	SUM	237,636	206,861	119,401	6,411	368	68,735
<u>Transmission O & M</u>								
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	<u>Transmission</u>	1.08	26,470	19,089	11,913	550	25	5,745
34.05	<u>Total Transmission O & M</u>	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%
<u>Distribution O & M</u>								
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	<u>Is Equipment</u>	3.14	80	80	0	0	0	0
35.08	<u>Total Distribution O & M</u>	SUM	82,168	81,943	55,328	3,724	177	15,015

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
<u>Expenses</u>								
<u>Production O & M</u>								
<u>Energy Related Prod O & M</u>								
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
<u>Demand Related Prod O & M</u>								
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
<u>Transmission O & M</u>								
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%
<u>Distribution O & M</u>								
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
<u>Customer Accounting</u>								
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 Comp	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
<u>Administrative & General Expenses</u>								
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	-938
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	<u>Ratio</u>		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
<u>Customer Accounting</u>								
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 Comp	3.06	0	0	0	0	0	0
36.05	<u>Uncollectibles</u>	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
<u>Administrative & General Expenses</u>								
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	<u>Ratio</u>		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
<u>Rate Base Adjustments</u>								
<u>Additive Adjustments</u>								
<u>Plant Held For Future Use</u>								
41.01	Transmission	1.08	6,602	4,761	2,971	137	6	1,433
41.02	Distribution	3.02	<u>1,673</u>	<u>1,665</u>	<u>1,062</u>	<u>60</u>	<u>2</u>	<u>467</u>
41.03	Total Land Held For Future Use	SUM	8,275	6,426	4,033	197	8	1,900
<u>Construction Work In Progress</u>								
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	<u>-66,597</u>	<u>-60,830</u>	<u>-37,402</u>	<u>-1,766</u>	<u>-85</u>	<u>-18,705</u>
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
<u>Working Capital</u>								
<u>Materials And Supplies</u>								
<u>Fuel Supplies</u>								
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	0	0	0	0	0	0
44.04	Total Fuel Stocks	SUM	139,958	126,090	63,564	4,001	262	48,648
<u>Plant Materials & Supplies</u>								
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
<u>Miscellaneous Working Capital</u>								
47.01	OPEB - D.A. Retail	8.18	-136,685	-136,685	-88,687	-5,499	-339	-33,866
47.02	OPEB - DA Wholesale	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	<u>8,995</u>	<u>8,285</u>	<u>5,307</u>	<u>298</u>	<u>14</u>	<u>2,115</u>
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
<u>Preliminary Summary</u>								
49.01	Total Additive Adjustments		91,150	78,953	49,954	2,642	121	21,593
49.02	Total Working Capital		<u>153.1</u>	<u>128,172</u>	<u>60,451</u>	<u>2,405</u>	<u>-54</u>	<u>53,281</u>
49.03	Total Rate Base Adjustments		244,307	207,126	110,405	5,046	67	74,874
<u>Rate Base Calculation</u>								
49.04	Net Electric Plant In Service		3,742,339	3,461,777	2,244,896	129,294	5,795	859,856
49.05	Adjustments		<u>244,307</u>	<u>207,126</u>	<u>110,405</u>	<u>5,046</u>	<u>67</u>	<u>74,874</u>
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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Rate Base Adjustments</u>								
<u>Additive Adjustments</u>								
<u>Plant Held For Future Use</u>								
41.01	Transmission	1.08	12	196	5	0	0	1,841
41.02	Distribution	3.02	<u>8</u>	<u>55</u>	<u>12</u>	<u>0</u>	<u>0</u>	<u>8</u>
41.03	Total Land Held For Future Use	SUM	20	251	17	0	0	1,849
<u>Construction Work In Progress</u>								
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	<u>-170</u>	<u>-2,614</u>	<u>-89</u>	<u>0</u>	<u>0</u>	<u>-5,767</u>
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
<u>Working Capital</u>								
<u>Materials And Supplies</u>								
<u>Fuel Supplies</u>								
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 I - 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
<u>Plant Materials & Supplies</u>								
45.01	Amount Allocable	20.06	210	2,676	242	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	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
<u>Miscellaneous Working Capital</u>								
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	0	0	0	573
47.08	Adj K - Section 1341	20.06	<u>21</u>	<u>262</u>	<u>2</u>	<u>153</u>	<u>92</u>	<u>710</u>
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
<u>Preliminary Summary</u>								
49.01	Total Additive Adjustments		207	2,804	189	900	544	12,197
49.02	Working Capital		<u>593</u>	<u>7,774</u>	<u>328</u>	<u>2,124</u>	<u>1,270</u>	<u>24,985</u>
49.03	Total Rate Base Adjustments		800	10,578	517	3,024	1,814	37,181
<u>Rate Base Calculation</u>								
49.04	Net Electric Plan In Service		8,633	103,674	10,940	59,654	39,034	280,562
49.05	Adjustments		<u>800</u>	<u>10,578</u>	<u>517</u>	<u>3,024</u>	<u>1,814</u>	<u>37,181</u>
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 Re enues	DA	1,509,008	1,397,246	886,989	61,766	2,542	359,989
	<u>Revenue Credits</u>							
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	<u>147</u>	<u>147</u>	<u>130</u>	<u>10</u>	<u>1</u>	<u>5</u>
52.10	Total Revenue Credits	SUM	39,039	37,557	26,948	1,792	103	7,455
53.01	<u>Total Present Revenues</u>	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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtaillable 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
<u>Revenue Credits</u>								
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	<u>0</u>	<u>0</u>	<u>1</u>	<u>0</u>	<u>0</u>	<u>0</u>
52.10	Total Revenue Credits	SUM	75	789	133	159	102	1,482
53.01	<u>Total Present Revenues</u>	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	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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	<u>28,831</u>	<u>20,791</u>	<u>12,976</u>	<u>599</u>	<u>28</u>	<u>6,257</u>
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	Is Equipment	3.14	<u>90</u>	<u>90</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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	188
57.03	Adj Sebring	8.17	<u>-2,208</u>	<u>-2,085</u>	<u>-1,353</u>	<u>-84</u>	<u>-5</u>	<u>-517</u>
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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtaillable 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	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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	<u>54</u>	<u>858</u>	<u>20</u>	<u>0</u>	<u>0</u>	<u>8,040</u>
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	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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	<u>-5</u>	<u>-6</u>	<u>-10</u>	<u>-26</u>	<u>-16</u>	<u>-123</u>
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
 PUBLIC 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
<u>Taxes Other Than Inc & Rev</u>							
<u>Real Estate & Property Tax</u>							
59.01	20.06	85,272	78,544	50,310	2,824	128	20,047
59.02	10.10	<u>102</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
59.03	SUM	85,374	78,544	50,310	2,824	128	20,047
60.01	8.17	14,159	13,373	8,677	538	33	3,313
61.01	SUM	99,533	91,917	58,987	3,362	161	23,361
<u>Other Taxes & Misc Expenses</u>							
62.01	9.03	139,119	139,119	88,314	6,150	253	35,843
62.02	20.06	-1,891	-1,742	-1,116	-63	-3	-445
62.03	9.03	<u>-138,166</u>	<u>-138,166</u>	<u>-87,709</u>	<u>-6,108</u>	<u>-251</u>	<u>-35,597</u>
62.04	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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtailable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Taxes Other Than Inc & Rev</u>								
<u>Real Estate & Property Tax</u>								
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
<u>Other Taxes & Misc Expenses</u>								
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 M - Exclude Franchise, Grt	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 Demand	Gen Serv. 100% LF	Gen. Serv. Demand
<u>Tax Calculations</u>								
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	<u>-98,595</u>	<u>-91,128</u>	<u>-58,476</u>	<u>-3,342</u>	<u>-160</u>	<u>-23,162</u>
63.05	Net Income Before Taxes	SUM	629,700	590,360	370,171	30,972	760	158,780
63.06	Less Interest Synchronization	CALC	-101,679	-93,575	-60,072	-3,426	-150	-23,840
63.07	Additions & Deductions	20.06	<u>95,492</u>	<u>87,958</u>	<u>56,340</u>	<u>3,162</u>	<u>144</u>	<u>22,450</u>
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

EXHIBIT SLB-4

Line No.	Allocators	Alloc.	Curtable Service	Interruptible Service	Lighting Energy	Lighting Fixture/Maint.	Lighting Poles	FERC Jurisdiction
<u>Tax Calculations</u>								
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 Synchronization	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	2,132
63.11	Federal Taxable Income		1,944	16,547	1,970	5,358	2,012	36,638
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.		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	<u>-197,178</u>	<u>-185,642</u>	<u>-115,782</u>	<u>-10,410</u>	<u>-226</u>	<u>-50,524</u>
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