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EI801-03-AR

OMB No. 1902-0021
(Expires 3/31/2005)

OFFICIAL COPY
Division of
Economic Regulation
FPSC

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

RECEIVED
FLORIDA PUBLIC SERVICE COMMISSION
04 MAY -3 AM 10:55
DIVISION OF ECONOMIC REGULATION

Exact Legal Name of Respondent (Company)	Year of Report
Florida Power Corporation – Progress Energy	Dec. 31, 2003

Deloitte.

Deloitte & Touche LLP
Suite 1800
150 Fayetteville Street Mall
Raleigh, NC 27601
USA

Tel: +1 919 546 8000
Fax: +1 919 833 3276
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Progress Energy Florida, Inc.
Raleigh, North Carolina

We have audited the balance sheet—regulatory basis of Florida Power Corporation d/b/a Progress Energy Florida, Inc. as of December 31, 2003, and the related statements of income—regulatory basis; retained earnings—regulatory basis; cash flows—regulatory basis, and accumulated other comprehensive income, comprehensive income, and hedging activities—regulatory basis for the year ended December 31, 2003, included on pages 110 through 123.39 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in page 123, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of Progress Energy Florida, Inc. at December 31, 2003, and the results of its operations and its cash flows for the year ended December 31, 2003, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of Progress Energy Florida, Inc. and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

February 20, 2004
Raleigh, North Carolina

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, Licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

II. Who Must Submit

Each major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of The Federal Power Act (18 CFR 101), must submit this form.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds
one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus Losses).

III. What and Where to Submit

(a) Submit this form electronically through the Form 1 Submission Software and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as the electronic filing, that the signer knows the contents of the paper copies and electronic filing, and that the contents as stated in the copies and electronic filing are true to the best knowledge and belief of the signer.

(b) Submit, immediately upon publication, four (4) copies of the Latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a Letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent Licensed public accountant certified or Licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 41.10-41.12 for specific qualifications.)

III. What and Where to Submit (Continued)

(c) Continued

Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

When accompanying this form, insert the Letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the office of the Secretary at the address indicated at III (a).

Use the following format for the Letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied . Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statements of ____________ for the year ended on which we have reported separately under date of ____________. We have also reviewed schedules ______________________________________ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE. Room 2A ES-1
Washington, DC 20426
(202) 208-2474

IV. When to Submit

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for this collection of information is estimated to average 1,217 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (Attention: Mr. Michael Miller, CI-1); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if this collection of information does not display a valid control number. (44 U.S.C. 3512(a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current year's amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, submit the electronic filing using the Form 1 Submission Software and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a). Resubmissions must be numbered sequentially on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

VIII. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit: ...(3) "Corporation" means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shalt not include 'municipalities, as hereinafter defined;

(4) "Person" means an individual or a corporation;

(5) "Licensee" means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) "Municipality" means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry an the business of developing, transmitting, unitizing, or distributing power;..."

(11) "Project" means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered:

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission my prescribe the manner and form in which such reports shalt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act ... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing..."

FERC FORM NO. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent Florida Power Corporation		02 Year of Report Dec. 31, 2003
03 Previous Name and Date of Change *(if name changed during year)* / /		
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* 100 Central Avenue, St. Petersburg, FL 33701-3324		
05 Name of Contact Person Lori Cross		06 Title of Contact Person Manager - Regulatory Acctg.
07 Address of Contact Person *(Street, City, State, Zip Code)* 100 Central Avenue, St. Petersburg, FL 33701-3324		
08 Telephone of Contact Person, *Including Area Code* (727) 820-5128	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/2003

ATTESTATION		
The undersigned officer certifies that he/she has examined the accompanying report: that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.		
01 Name Robert H. Bazemore, Jr.	03 Signature	04 Date Signed *(Mo, Da, Yr)* / /
02 Title Vice President and Controller		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	116 - None
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	None
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	None
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	None
24	Unrecovered Plant and Regulatory Study Costs	230	None
25	Other Regulatory Assets	232	
26	Miscellaneous Deferred Debits	233	
27	Accumulated Deferred Income Taxes	234	
28	Capital Stock	250-251	
29	Other Paid-in Capital	253	
30	Capital Stock Expense	254	None
31	Long-Term Debit	256-257	
32	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
33	Taxes Accrued, Prepaid and Charged During the Year	262-263	
34	Accumulated Deferred Investment Tax Credits	266-267	
35	Other Deferred Credits	269	
36	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	
46	Transmission of Electricity by Others	332	None
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	None
50	Research, Development and Demonstration Activities	352-353	None
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	None
53	Electric Energy Account	401	
54	Monthly Peaks and Output	401	
55	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
56	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	None
57	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	None
58	Generating Plant Statistics (Small Plants)	410-411	None
59	Transmission Line Statistics	422-423	
60	Transmission Lines Added During Year	424-425	
61	Substations	426-427	
62	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Robert H. Bazemore, Jr.
Vice President and Controller
412 S. Wilmington Street
Raleigh, NC 27601

Florida Power Corporation
100 Central Avenue
St. Petersburg, FL 33701-3324

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Florida
July 18, 1899

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the state of Florida

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Florida Power Corporation is a wholly-owned subsidiary of Progress Energy, Inc., a North Carolina corporation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and CEO	H. William Habermeyer, Jr.	479,838
3			
4	Group President	William S. Orser	953,926
5			
6	Executive VP	William D. Johnson	843,166
7			
8	Executive VP	Peter M. Scott, III	785,902
9			
10	Senior Vice President	C. S. Hinnant	641,437
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Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec 31, 2003

FOOTNOTE DATA

Schedule Page: 104 Line No.: 1 Column: a

Listed on Page 104 is the compensation information for the CEO of Florida Power and the four most highly compensated officers other than the CEO for the year ended December 31, 2003. These individuals were identified in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission.

Schedule Page: 104 Line No.: 1 Column: c

Salary for year is annual compensation, which includes Salary, Bonus and Other Annual Compensation, as determined in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	William Cavanaugh, III, Chairman	PO Box 1551, Raleigh, NC 27602
2	Fred N. Day, IV, Executive Vice President	PO Box 1551, Raleigh, NC 27602
3	H. William Habermeyer, Jr., President and CEO	100 Central Avenue, St. Petersburg, FL 33701
4	William D. Johnson, Executive Vice President	PO Box 1551, Raleigh, NC 27602
5	Robert B. McGehee	PO Box 1551, Raleigh, NC 27602
6	William S. Orser, Group President	PO Box 1551, Raleigh, NC 27602
7	Peter M. Scott, III, Executive Vice President	PO Box 1551, Raleigh, NC 27602
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11	Note: Florida Power Corporation Board does not have an	
12	Executive Committee	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. CHANGES IN AND IMPORTANT ADDITIONS TO FRANCHISE RIGHTS

In 2003, one (1) new franchise was approved with a municipality with which the Company had an existing agreement; two (2) new franchises were signed with municipalities where previous agreements had expired. Florida Power Corporation remits a franchise fee to municipalities collected from customers based on 6% of the retail revenues for specific revenue classes within these cities having the franchise agreements and based on the provisions of the negotiated agreement.

The one (1) new franchise approved with an existing franchise city was with the city of Lake Mary. This agreement has a 10-year term without a purchase option. The agreement provides that the city may amend the agreement during that 10-year term to a 30-year term with a purchase option exercisable at the end of the 30-years.

The two (2) new franchises signed with cities where previous franchises had expired were with the cities of Casselberry and Longwood. These agreements have 30-year terms with purchase options exercisable at the end of the 30-year term.

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

Florida Power Corporation purchased from Tampa Electric Company a majority of the Circuit No. 230601, including Transmission Poles, Structures and Conductors, between Pebbledale and Florida Power's Barcola Substation. The appropriate FERC 203 filing was dated May 23, 2003. FERC's Order Authorizing Disposition of Jurisdictional Facilities (Docket No. EC03-93-000) was issued July 8, 2003.

4. IMPORTANT LEASEHOLDS

None

5. IMPORTANT EXTENSION OR REDUCTION TO TRANSMISSION OR DISTRIBUTION SYSTEM

None

6. OBLIGATIONS INCURRED AS A RESULT OF ISSUANCE OF SECURITIES OR ASSUMPTIONS OF LIABILITIES OR GUARANTEES

a) On February 21, 2003, Florida Power Corporation issued $425 million of First Mortgage Bonds, 4.80% Series due March 1, 2013.

b) On February 21, 2003, Florida Power Corporation issued $225 million of First Mortgage Bonds, 5.90% Series due March 1, 2033.

c) On November 21, 2003, Florida Power Corporation issued $300 million of First Mortgage Bonds, 5.10% Series due December 1, 2015.

d) During 2003, Florida Power Corporation issued $2,452,700,000 in commerical paper and redeemed a total of $2,709,800,000. The average daily weighted rate during the period was 1.2941%.

Authorization of items under Note 6 was received from Florida Public Service Commission under Order PSC-02-1631-FOF-EI.

7. CHANGES IN ARTICLES OF INCORPORATION OR AMENDMENTS TO CHARTER

   None

8. STATE THE ESTIMATED ANNUAL EFFECT AND NATURE OF ANY IMPORTANT WAGE SCALE CHANGES DURING THE YEAR

   None

9. LEGAL PROCEEDINGS

   See Part I, Item 3. Legal Proceedings in the Florida Progress Corporation/Florida Power Corporation Annual Report on Form 10-K for the year ended December 31, 2003, which is filed with this report.

10. DESCRIBE BRIEFLY ANY MATERIALLY IMPORTANT TRANSACTIONS OF THE RESPONDENT NOT DISCLOSED ELSEWHERE IN THIS REPORT

    None

11. RESERVED

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	7,484,946,551	8,157,601,890
3	Construction Work in Progress (107)	200-201	426,641,479	328,267,599
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,911,588,030	8,485,869,489
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	4,072,041,771	4,020,429,793
6	Net Utility Plant (Enter Total of line 4 less 5)		3,839,546,259	4,465,439,696
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	506,390,589	214,555,238
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	466,130,870	145,446,991
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		40,259,719	69,108,247
10	Net Utility Plant (Enter Total of lines 6 and 9)		3,879,805,978	4,534,547,943
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)		8,633,157	9,196,513
15	(Less) Accum. Prov. for Depr. and Amort. (122)		1,975,045	2,284,760
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	0	0
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		1,000	203,603
21	Special Funds (125-128)		354,284,659	466,111,154
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		360,943,771	473,226,510
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		13,907,456	8,475,582
25	Special Deposits (132-134)		1,702,600	0
26	Working Fund (135)		25,541	0
27	Temporary Cash Investments (136)		0	0
28	Notes Receivable (141)		524,525	659,150
29	Customer Accounts Receivable (142)		177,165,784	185,192,376
30	Other Accounts Receivable (143)		14,974,284	7,617,236
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,467,016	2,229,825
32	Notes Receivable from Associated Companies (145)		2,465,011	0
33	Accounts Receivable from Assoc. Companies (146)		42,511,021	7,390,823
34	Fuel Stock (151)	227	111,111,824	90,516,921
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	118,219,682	130,195,768
38	Merchandise (155)	227	237,806	424,410
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	1,237,884	912,089
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	5,473,989	9,361,873
44	Gas Stored Underground - Current (164.1)		0	0
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		226,463,934	224,329,737
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		0	0
49	Rents Receivable (172)		180,175	256,095
50	Accrued Utility Revenues (173)		60,481,187	58,686,140
51	Miscellaneous Current and Accrued Assets (174)		0	0
52	Derivative Instrument Assets (175)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	Derivative Instrument Assets - Hedges (176)		0	0
54	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 53)		774,215,687	721,788,375
55	**DEFERRED DEBITS**			
56	Unamortized Debt Expenses (181)		14,502,732	24,634,022
57	Extraordinary Property Losses (182.1)	230	0	0
58	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
59	Other Regulatory Assets (182.3)	232	222,440,272	368,450,412
60	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
61	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
62	Clearing Accounts (184)		137,674	105
63	Temporary Facilities (185)		0	0
64	Miscellaneous Deferred Debits (186)	233	11,041,003	12,913,205
65	Def. Losses from Disposition of Utility Plt. (187)		0	0
66	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
67	Unamortized Loss on Reaquired Debt (189)		19,756,368	32,880,006
68	Accumulated Deferred Income Taxes (190)	234	136,798,935	133,953,304
69	Unrecovered Purchased Gas Costs (191)		0	0
70	TOTAL Deferred Debits (Enter Total of lines 56 thru 69)		404,676,984	572,831,054
71	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,54,70)		5,419,642,420	6,302,393,882

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 12/31/2003	Year of Report Dec. 31, 2003

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	354,405,315	354,405,315
3	Preferred Stock Issued (204)	250-251	33,496,700	33,496,700
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	31,115	31,115
7	Other Paid-In Capital (208-211)	253	726,821,247	726,821,247
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	969,794,924	1,061,364,677
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	122(a)(b)	-2,683,913	-3,783,531
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)		2,081,865,388	2,172,335,523
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	1,050,865,000	1,570,865,000
18	(Less) Reaquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	416,900,003	379,500,000
21	Unamortized Premium on Long-Term Debt (225)		0	0
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,432,910	3,865,412
23	TOTAL Long-Term Debt (Enter Total of lines 17 thru 22)		1,461,332,093	1,946,499,588
24	**OTHER NONCURRENT LIABILITIES**			
25	Obligations Under Capital Leases - Noncurrent (227)		0	0
26	Accumulated Provision for Property Insurance (228.1)		35,631,182	40,915,219
27	Accumulated Provision for Injuries and Damages (228.2)		21,544,019	15,880,703
28	Accumulated Provision for Pensions and Benefits (228.3)		143,954,621	155,650,203
29	Accumulated Miscellaneous Operating Provisions (228.4)		65,345,257	68,064,326
30	Accumulated Provision for Rate Refunds (229)		5,708,933	17,880,360
31	Asset Retirement Obligations (230)		0	319,276,955
32	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 25 thru 31)		272,184,012	617,667,766
33	**CURRENT AND ACCRUED LIABILITIES**			
34	Notes Payable (231)		257,100,000	0
35	Accounts Payable (232)		142,102,415	152,433,782
36	Notes Payable to Associated Companies (233)		237,425,461	363,286,516
37	Accounts Payable to Associated Companies (234)		88,661,370	73,953,595
38	Customer Deposits (235)		121,997,999	126,764,870
39	Taxes Accrued (236)	262-263	33,517,521	30,152,914
40	Interest Accrued (237)		55,675,447	42,062,713
41	Dividends Declared (238)		0	0
42	Matured Long-Term Debt (239)		0	0
43	Matured Interest (240)		0	0
44	Tax Collections Payable (241)		9,443,333	9,233,983
45	Miscellaneous Current and Accrued Liabilities (242)		44,750,808	60,454,475

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	Obligations Under Capital Leases-Current (243)		0	0
47	Derivative Instrument Liabilities (244)		0	0
48	Derivative Instrument Liabilities - Hedges (245)		518,301	0
49	TOTAL Current & Accrued Liabilities (Enter Total of lines 34 thru 48)		991,192,655	858,342,848
50	**DEFERRED CREDITS**			
51	Customer Advances for Construction (252)		5,913	0
52	Accumulated Deferred Investment Tax Credits (255)	266-267	47,422,508	41,351,508
53	Deferred Gains from Disposition of Utility Plant (256)		0	0
54	Other Deferred Credits (253)	269	8,805,004	11,404,747
55	Other Regulatory Liabilities (254)	278	85,112,047	196,566,595
56	Unamortized Gain on Reaquired Debt (257)		0	0
57	Accumulated Deferred Income Taxes (281-283)	272-277	471,722,800	458,225,307
58	TOTAL Deferred Credits (Enter Total of lines 51 thru 57)		613,068,272	707,548,157
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68			0	0
69			0	0
70			0	0
71			0	0
72	TOTAL Liab and Other Credits (Enter Total of lines 15,23,32,49,58)		5,419,642,420	6,302,393,882

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 8, 10, and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	3,140,833,180	3,082,732,881
3	Operating Expenses			
4	Operation Expenses (401)	320-323	2,107,621,828	1,841,321,512
5	Maintenance Expenses (402)	320-323	134,373,529	121,747,250
6	Depreciation Expense (403)	336-337	243,276,489	230,561,841
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,491,608	
8	Amort. & Depl. of Utility Plant (404-405)	336-337	17,162,225	15,636,206
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-367,763	-313,018
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		48,446,911	48,971,278
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits (407.3)		32,952,895	79,858,589
13	(Less) Regulatory Credits (407.4)		209,125,853	81,554,028
14	Taxes Other Than Income Taxes (408.1)	262-263	241,134,838	227,699,247
15	Income Taxes - Federal (409.1)	262-263	160,594,108	190,937,414
16	- Other (409.1)	262-263	27,833,613	30,456,757
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	83,576,000	94,906,000
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	110,498,000	125,739,000
19	Investment Tax Credit Adj. - Net (411.4)	266	-6,071,000	-6,452,000
20	(Less) Gains from Disp. of Utility Plant (411.6)			
21	Losses from Disp. of Utility Plant (411.7)			
22	(Less) Gains from Disposition of Allowances (411.8)			
23	Losses from Disposition of Allowances (411.9)			
24	Accretion Expense (411.10)		16,472,558	
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,788,873,986	2,668,038,048
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		351,959,194	414,694,833

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.
8. Enter on page 123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.
10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 26, and report the information in the blank space on page 123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
3,140,833,180	3,082,732,881					2
						3
2,107,621,828	1,841,321,512					4
134,373,529	121,747,250					5
243,276,489	230,561,841					6
1,491,608						7
17,162,225	15,636,206					8
-367,763	-313,018					9
48,446,911	48,971,278					10
						11
32,952,895	79,858,589					12
209,125,853	81,554,028					13
241,134,838	227,699,247					14
160,594,108	190,937,414					15
27,833,613	30,456,757					16
83,576,000	94,906,000					17
110,498,000	125,739,000					18
-6,071,000	-6,452,000					19
						20
						21
						22
						23
16,472,558						24
2,788,873,986	2,668,038,048					25
351,959,194	414,694,833					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
27	Net Utility Operating Income (Carried forward from page 114)		351,959,194	414,694,833
28	Other Income and Deductions			
29	Other Income			
30	Nonutilty Operating Income			
31	Revenues From Merchandising, Jobbing and Contract Work (415)			
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			
33	Revenues From Nonutility Operations (417)		5,424,708	16,937,617
34	(Less) Expenses of Nonutility Operations (417.1)		7,245,818	15,141,126
35	Nonoperating Rental Income (418)		-212,998	-213,733
36	Equity in Earnings of Subsidiary Companies (418.1)	119		
37	Interest and Dividend Income (419)		1,751,970	1,765,509
38	Allowance for Other Funds Used During Construction (419.1)		11,587,391	2,306,571
39	Miscellaneous Nonoperating Income (421)		3,688,383	3,029,451
40	Gain on Disposition of Property (421.1)			484,436
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		14,993,636	9,168,725
42	Other Income Deductions			
43	Loss on Disposition of Property (421.2)		161,752	
44	Miscellaneous Amortization (425)	340		
45	Miscellaneous Income Deductions (426.1-426.5)	340	7,556,695	13,178,073
46	TOTAL Other Income Deductions (Total of lines 43 thru 45)		7,718,447	13,178,073
47	Taxes Applic. to Other Income and Deductions			
48	Taxes Other Than Income Taxes (408.2)	262-263	151,821	150,599
49	Income Taxes-Federal (409.2)	262-263	-15,135,928	-19,325,502
50	Income Taxes-Other (409.2)	262-263	-1,098,688	-1,446,849
51	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7,573,000	447,000
52	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		511,000
53	Investment Tax Credit Adj.-Net (411.5)			
54	(Less) Investment Tax Credits (420)			
55	TOTAL Taxes on Other Income and Deduct. (Total of 48 thru 54)		-8,509,795	-20,685,752
56	Net Other Income and Deductions (Enter Total lines 41, 46, 55)		15,784,984	16,676,404
57	Interest Charges			
58	Interest on Long-Term Debt (427)		101,279,778	99,385,622
59	Amort. of Debt Disc. and Expense (428)		2,892,916	1,510,215
60	Amortization of Loss on Reaquired Debt (428.1)		1,985,749	1,831,708
61	(Less) Amort. of Premium on Debt-Credit (429)			
62	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
63	Interest on Debt to Assoc. Companies (430)	340	2,001,086	595,086
64	Other Interest Expense (431)	340	-11,487,835	6,602,013
65	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,650,620	2,659,110
66	Net Interest Charges (Enter Total of lines 58 thru 65)		91,021,074	107,265,534
67	Income Before Extraordinary Items (Total of lines 27, 56 and 66)		276,723,104	324,105,703
68	Extraordinary Items			
69	Extraordinary Income (434)		19,631,385	
70	(Less) Extraordinary Deductions (435)			
71	Net Extraordinary Items (Enter Total of line 69 less line 70)		19,631,385	
72	Income Taxes-Federal and Other (409.3)	262-263		
73	Extraordinary Items After Taxes (Enter Total of line 71 less line 72)		19,631,385	
74	Net Income (Enter Total of lines 67 and 73)		296,354,489	324,105,703

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		969,794,924
2	Changes		
3	Adjustments to Retained Earnings (Account 439)		
4			
5			
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		
10			
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		
16	Balance Transferred from Income (Account 433 less Account 418.1)		296,354,489
17	Appropriations of Retained Earnings (Acct. 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			-1,511,860
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,511,860
30	Dividends Declared-Common Stock (Account 438)		
31			-203,272,876
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-203,272,876
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		1,061,364,677
	APPROPRIATED RETAINED EARNINGS (Account 215)		
39			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)		
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)		
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total 38, 47)		1,061,364,677
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
49	Balance-Beginning of Year (Debit or Credit)		
50	Equity in Earnings for Year (Credit) (Account 418.1)		
51	(Less) Dividends Received (Debit)		
52			
53	Balance-End of Year (Total lines 49 thru 52)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	296,354,489
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	245,122,881
5	Amortization of - Limited and Electric Plant, Non-fuel, Load Mmgt	27,211,988
6	Amortization of - Debt premium, expense and loss on reacquisition	2,548,134
7	(Gain) Loss on Sale of Assets	161,752
8	Deferred Income Taxes (Net)	-19,349,002
9	Investment Tax Credit Adjustment (Net)	-6,071,000
10	Net (Increase) Decrease in Receivables	33,607,193
11	Net (Increase) Decrease in Inventory	4,544,328
12	Net (Increase) Decrease in Allowances Inventory	325,794
13	Net Increase (Decrease) in Payables and Accrued Expenses	12,654,505
14	Net (Increase) Decrease in Other Regulatory Assets	-145,335,362
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,593,129
16	(Less) Allowance for Other Funds Used During Construction	11,587,392
17	(Less) Undistributed Earnings from Subsidiary Companies	
18	Other (provide details in footnote): Change in Current Assets	-221,374
19	Change in Pension	2,355,570
20	Change in Other, net	29,526,277
21		
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	470,255,652
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-542,401,338
27	Gross Additions to Nuclear Fuel	-50,890,321
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	-1,303,727
30	(Less) Allowance for Other Funds Used During Construction	5,650,619
31	Other (provide details in footnote):	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-600,246,005
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	624,896
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	-10,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

STATEMENT OF CASH FLOWS

4. Investing Activities include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.
5. Codes used:
(a) Net proceeds or payments. (c) Include commercial paper.
(b) Bonds, debentures and other long-term debt. (d) Identify separately such items as investments, fixed assets, intangibles, etc.
6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other (provide details in footnote):	
54		
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	-599,631,109
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	934,659,087
62	Preferred Stock	
63	Common Stock	
64	Other (provide details in footnote): Intercompany Notes	126,706,524
65		
66	Net Increase in Short-Term Debt (c)	
67	Other (provide details in footnote):	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,061,365,611
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	-476,216,434
74	Preferred Stock	
75	Common Stock	
76	Other (provide details in footnote): Dividends to Parent	-203,272,876
77	Dividends on Preferred Stock	-1,511,859
78	Net Decrease in Short-Term Debt (c)	-258,149,000
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	122,215,442
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	-7,160,015
87		
88	Cash and Cash Equivalents at Beginning of Year	15,635,597
89		
90	Cash and Cash Equivalents at End of Year	8,475,582

Name of Respondent	This Report Is:	Date of Report	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

FERC/GAAP DIFFERENCES

Florida Power Corporation d/b/a Progress Energy Florida's (PEF) financial statements have been prepared in conformity with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. These requirements differ from generally accepted accounting principles related to (1) the presentation of current portions of long-term debt and preferred stock, (2) the presentation of current portion of deferred income taxes, (3) the presentation of SFAS No. 109 regulatory assets and liabilities, (4) the reclassification of the rate case accrual from a long-term liability to a current liability, (5) the presentation of cost of removal assets and liabilities and (6) the presentation of extraordinary items.

PEF's Notes to Financial Statements have been combined with Florida Progress Corporation and are prepared in conformity with generally accepted accounting principles. Accordingly, certain footnotes are not reflective of PEF's Financial Statements contained herein.

OTHER DISCLOSURES

Cash payments for interest and income taxes for 2003 were $85 million and $177 million, respectively.

FLORIDA PROGRESS CORPORATION AND FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA NOTES TO FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies

A. Organization

Florida Progress Corporation (the Company or Florida Progress) is a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). The Company became subject to the regulations of PUHCA when it was acquired by CP&L Energy, Inc. in November 2000. CP&L Energy, Inc. subsequently changed its name to Progress Energy, Inc. (Progress Energy or the Parent). Florida Progress' two primary subsidiaries are Florida Power Corporation (Progress Energy Florida or PEF) and Progress Fuels Corporation (Progress Fuels). Effective January 1, 2003, Florida Power Corporation began doing business under the assumed name Progress Energy Florida, Inc. The legal name of the entity has not changed. The current corporate and business unit structure remains unchanged. Throughout the report, the terms utility and regulated will be used to discuss items pertaining to Progress Energy Florida. Diversified business and nonregulated will be used to discuss the subsidiaries of Florida Progress excluding Progress Energy Florida.

B. Basis of Presentation

The financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The financial statements include the financial results of the Company and its majority-owned subsidiaries. Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

Unconsolidated investments in companies over which the Company does not have control, but has the ability to exercise significant influence over operating and financial policies (generally 20% - 50% ownership), are accounted for under the equity method of accounting. Other investments are stated principally at cost. These equity and cost investments, which total approximately $22 and $14 million at December 31, 2003 and 2002, respectively, are included in miscellaneous property and investments on the Company's Consolidated Balance Sheets. The primary components of this balance are the Company's investment in FPC Capital I of $9 million in 2003 and the Company's investment in affordable housing of $8 and $9 million at December 31, 2003 and 2002, respectively.

The results of operations of the Rail Services segment are reported one month in arrears. During 2003, the Company ceased recording portions of the Energy and Related Services segment operations one month in arrears. The net impact of this action increased net income by $2 million for the year.

Certain amounts for 2002 have been reclassified to conform to the 2003 presentation.

C. Significant Accounting Policies

Use of Estimates and Assumptions
In preparing financial statements that conform with GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

Revenue Recognition
The Company recognizes electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility revenues earned when service has been delivered but not billed by the end of the accounting period. Diversified business revenues are recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Revenues relating to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties.

Fuel Cost Deferrals
Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the regulators of PEF. Those clauses allow PEF to recover fuel costs and portions of purchased power costs through surcharges on customer rates.

Excise Taxes
The Company collects from customers certain excise taxes levied by the state or local government upon the customer. PEF accounts for excise taxes on a gross basis. For the years ended December 31, 2003 and 2002, gross receipts tax and franchise taxes of approximately $136 million and $132 million, respectively, are included in taxes other than on income on the accompanying Statements of Income and Comprehensive Income. These approximate amounts are also included in electric operating revenues.

Income Taxes
Progress Energy and its affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to Florida Progress and PEF in accordance with the Intercompany Income Tax Allocation Agreement (Tax Agreement). The Tax Agreement provides an allocation that recognizes positive and negative corporate taxable income. The Tax Agreement provides for an equitable method of apportioning the carry over of uncompensated tax benefits. Progress Energy tax benefits not related to acquisition interest expense are allocated to profitable subsidiaries, beginning in 2002, in accordance with a PUHCA order. Income taxes are provided as if Florida Progress and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax bases of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuel are deferred to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns (See Note 13).

Stock-Based Compensation
The Company measures compensation expense for stock options as the difference between the market price of its common stock and the exercise price of the option at the grant date. The exercise price at which options are granted by the Company equals the market price at the grant date, and accordingly, no compensation expense has been recognized for stock option grants. For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an Amendment of FASB Statement No. 123," the estimated fair value of Progress Energy's stock options is amortized to expense over the options' vesting period. The following table illustrates the effect on net income for Florida Progress Corporation and PEF if the fair value method had been applied to all outstanding and unvested awards in each period:

(in millions) Florida Progress	**2003**	2002
Net income, as reported	**$ 447**	$ 235
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**3**	3
Pro forma net income	**$ 444**	$ 232

(in millions) Progress Energy Florida	**2003**	2002
Net income, as reported	**$ 297**	$ 325
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**2**	2
Pro forma net income	**$ 295**	$ 323

Utility Plant
Utility plant in service is stated at historical cost less accumulated depreciation. The Company capitalizes all construction-related direct labor and material costs of units of property as well as indirect construction costs. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property, and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal, disposal and decommission costs were charged to regulatory liabilities in 2003 and cost of removal in 2002. The Company follows the guidance in SFAS No. 143, "Accounting for Asset Retirement Obligations," to account for legal obligations associated with the retirement of certain tangible long-lived assets.

Depreciation and Amortization – Utility Plant
For financial reporting purposes, substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). The Florida Public Service Commission (FPSC) can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 7).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities is computed primarily on the units-of-production method and charged to fuel used in electric generation in the accompanying Statements of Income and Comprehensive Income. In the Company's retail jurisdictions, provisions for nuclear decommissioning costs are approved by the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the Federal Energy Regulatory Commission (FERC).

Cash and Cash Equivalents
The Company considers cash and cash equivalents to include cash on hand, cash in banks and temporary investments purchased with a maturity of three months or less.

Allowance for Doubtful Accounts
The Company maintains an allowance for doubtful accounts receivable, which totaled approximately $15 million and $28 million at December 31, 2003 and 2002, respectively, and is included in the accounts receivable balance in the accompanying Consolidated Balance Sheets. PEF's allowance for doubtful accounts receivable totaled $2 million at December 31, 2003 and 2002 and is included in the accounts receivable balance in the Balance Sheets.

Inventory
The Company accounts for inventory using the average-cost method.

Regulatory Assets and Liabilities
PEF's regulated operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, PEF records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A).

Diversified Business Property
Diversified business property is stated at cost less accumulated depreciation. If an impairment loss is recognized on an asset, the fair value becomes its new cost basis. The costs of renewals and betterments are capitalized. The cost of repairs and maintenance is charged to expense as incurred. Depreciation is computed on a straight-line basis over the estimated useful lives as indicated in Note 5B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

The Company uses the full cost method to account for its natural gas and oil properties. Under the full cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future costs to develop proved reserves. Except for costs on unproved properties and major development projects in progress, all costs are amortized using the units-of-production method over the life of the Company's proved reserves.

Goodwill and Intangible Assets
Effective January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), and no longer amortizes goodwill. Instead, goodwill is subject to at least an annual assessment for impairment by applying a two-step fair value-based test. This assessment could result in periodic impairment charges. Prior to the adoption of SFAS No. 142, the Company amortized goodwill on a straight-line basis over a period not exceeding 40 years. Intangible assets are being amortized based on the economic benefit of their respective lives.

Unamortized Debt Premiums, Discounts and Expenses
Long-term debt premiums, discounts and issuance expenses of PEF are amortized over the life of the related debt using the straight-line method. Any expenses or call premiums associated with the reacquisition of debt obligations by PEF are amortized over the applicable life using the straight-line method consistent with ratemaking treatment.

Derivatives
Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149. SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value (See Note 15).

Environmental
The Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies," have been met. Environmental expenditures are expensed as incurred or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable.

Impairment of Long-lived Assets and Investments
The Company reviews the recoverability of long-lived tangible and intangible assets whenever indicators exist. Examples of these

indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. The accounting for impairment of long-lived assets is based on SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which was adopted by the Company effective January 1, 2002. Prior to the adoption of this standard, impairments were accounted for under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," which was superceded by SFAS No. 144.

The Company reviews its investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. The Company considers various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If the Company determines that other-than-temporary decline exists in the value of its investments, it is the Company's policy to write-down these investments to fair value. See Note 9 for a discussion of impairment evaluations performed and charges taken.

Under the full cost method of accounting for natural gas and oil properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, the Company is required to write-down capitalized costs to this level. The Company performs this ceiling test calculation every quarter. No write-downs were required in 2003 and 2002.

Subsidiary Stock Transactions

Gains and losses realized as a result of common stock sales by the Company's subsidiaries are recorded in the Company's Consolidated Statements of Income and Comprehensive Income, except for any transactions that must be credited directly to equity in accordance with the provisions of SAB No. 51, "Accounting for Sales of Stock by a Subsidiary".

2. Impact of New Accounting Standards

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity"

In May 2003, the Financial Accounting Standard Board (FASB) issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." The adoption of SFAS No. 150 did not have an impact on the Company's financial position or results of operations as of and for the periods ended December 31, 2003.

EITF Issue No. 03-04, "Accounting for 'Cash Balance' Pension Plans"

In May 2003, the FASB Emerging Issues Task Force (EITF) reached consensus in EITF Issue No. 03-04, "Accounting for 'Cash Balance' Pension Plans" (EITF 03-04), to specifically address the accounting for certain cash balance pension plans. The consensus reached in EITF 03-04 requires certain cash balance pension plans to be accounted for as defined benefit plans. For cash balance plans described in the consensus, the consensus also requires the use of the traditional unit credit method for purposes of measuring the benefit obligation and annual cost of benefits earned as opposed to the projected unit credit method. The Company has historically accounted for its cash balance plan as a defined benefit plan; however, the Company was required to adopt the measurement provisions of EITF 03-04 at its cash balance plan's measurement date of December 31, 2003. Any differences in the measurement of the obligations as a result of applying the consensus were reported as a component of actuarial gain or loss. The on-going effects of this standard are dependent on other factors that also affect the determination of actuarial gains and losses and the subsequent amortization of such gains and losses. However, the adoption of EITF 03-04 is not expected to have a material effect on the Company's results of operations or financial position.

SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." The statement amends and clarifies SFAS No. 133 on accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. The new guidance incorporates decisions made as part of the Derivatives Implementation Group (DIG) process, as well as decisions regarding implementation issues raised in relation to the application of the definition of a derivative. SFAS No. 149 is generally effective for contracts entered into or modified after June

30, 2003. Interpretations and implementation issues with regard to SFAS No. 149 continue to evolve. The statement had no significant impact on the Company's accounting for contracts entered into subsequent to the statement's effective date (See Note 15). Future effects, if any, on the Company's results of operations and financial condition will be dependent on the specifics of future contracts entered into with regard to guidance provided by the statement.

FIN No. 46, "Consolidation of Variable Interest Entities"
In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN No. 46). This interpretation provides guidance related to identifying variable interest entities and determining whether such entities should be consolidated. FIN No. 46 requires an enterprise to consolidate a variable interest entity when the enterprise (*a*) absorbs a majority of the variable interest entity's expected losses, (*b*) receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Prior to the effective date of FIN No. 46, entities were generally consolidated by an enterprise that had control through ownership of a majority voting interest in the entity. FIN No. 46 originally applied immediately to variable interest entities created or obtained after January 31, 2003. During 2003, the Company did not participate in the creation of, or obtain a new variable interest in, any variable interest entity. In December 2003, the FASB issued a revision to FIN No. 46 (FIN No. 46R), which modified certain requirements of FIN No. 46 and allowed for the optional deferral of the effective date of FIN No. 46R until March 31, 2004. However, entities subject to FIN No. 46R that are deemed to be special-purpose entities (as defined in FIN No. 46R) must implement either FIN No. 46 or FIN No. 46R at December 31, 2003. The Company has elected to apply FIN No. 46 to special-purpose entities as of December 31, 2003. Because the Company expects additional transitional guidance to be issued, it has elected to apply FIN No. 46R to non-special-purpose entities as of March 31, 2004.

Prior to the adoption of FIN No. 46, the Company consolidated the FPC Capital I trust (the Trust), which holds FPC-obligated mandatorily redeemable preferred securities (See Note 11F). The Trust is a special-purpose entity as defined in FIN No. 46R, and therefore the Company applied FIN No. 46 to the Trust at December 31, 2003. The Trust is a variable interest entity, but the Company does not absorb a majority of the Trust's expected losses and therefore is not its primary beneficiary. Therefore, the Company deconsolidated the Trust at December 31, 2003. This deconsolidation resulted in recording an additional equity investment in the Trust of approximately $9 million and an increase in outstanding debt of $9 million. See Note 11F for a discussion of the Company's guarantees with the Trust.

The Company also has interests in several other variable interest entities created before January 31, 2003, for which the Company is not the primary beneficiary. These arrangements include equity investments in approximately six limited partnerships, limited liability corporations and venture capital funds. The aggregate maximum loss exposure at December 31, 2003 under these arrangements totals approximately $11 million. The creditors of these variable interest entities do not have recourse to the general credit of the Company in excess of the aggregate maximum loss exposure.

In February 2004, the Company became aware that certain long-term purchase power and tolling contracts may be considered variable interests under FIN No. 46R. The Company has various long-term purchase power and tolling contracts with other utilities and certain qualifying facility plants. The Company believes the counterparties to these contracts are not special-purpose entities and, therefore, FIN No. 46R would not apply to these contracts until March 31, 2004. The Company has not yet completed its evaluation of these contracts to determine if the Company needs to consolidate these counterparties under FIN No. 46R and will continue to monitor developing practice in this area.

3. Divestitures

A. Mesa Hydrocarbons, Inc. Divestiture

In October 2003, the Company sold certain gas-producing properties owned by Mesa Hydrocarbons, LLC, a wholly-owned subsidiary of Progress Fuels Corporation, which is included in the Fuels segment. Net proceeds of approximately $97 million were used to reduce debt. Because the Company utilizes the full cost method of accounting for its oil and gas operations, the pre-tax gain of approximately $18 million was applied to reduce the basis of the Company's other U.S. oil and gas investments and will prospectively result in a reduction of the amortization rate applied to those investments as production occurs.

B. Railcar Ltd. Divestiture

In December 2002, the Progress Energy Board of Directors adopted a resolution approving the sale of Railcar Ltd., a subsidiary included in the Rail Services segment. In accordance with SFAS No. 144, an estimated pre-tax impairment of $67 million on assets held for sale was recognized in December 2002 to write-down the assets to fair value less costs to sell. This impairment has been included in impairment of long-lived assets in the Company's Consolidated Statements of Income and Comprehensive Income (See Note 9).

The assets of Railcar Ltd. have been grouped as assets held for sale and are included in other current assets on the Company's Consolidated Balance Sheets at December 31, 2003 and 2002. The assets are recorded at approximately $75 million and $24 million at December 31, 2003 and 2002, respectively, which reflects the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell. The primary component of assets held for sale at December 31, 2003 was property and equipment of $74 million. The primary component of assets held for sale at December 31, 2002 was current assets of $22 million. The net increase in assets held for sale from December 31, 2002 to December 31, 2003 was primarily attributable to the purchase of railcars in 2003 that were subject to off-balance sheet obligations at December 31, 2002. In addition to the assets held for sale, the Company is subject to certain commitments under operating leases (See Note 19).

In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc. In November 2003, the asset purchase agreement was signed, and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million. The Company was relieved of the majority of the operating lease commitments when the assets were sold.

C. Inland Marine Transportation Divestiture

In November 2001, the Company completed the sale of the Inland Marine Transportation segment. The net gain on disposal of discontinued operations in the Company's Consolidated Statements of Income and Comprehensive Income for year ended December 31, 2002, represents the after-tax gain from the resolution of approximately $5 million of contingencies in the purchase agreement of the Inland Marine Transportation segment. In connection with the sale, the Company entered into environmental indemnification provisions covering both unknown and known sites. In 2003, the Company reduced the estimate for the environmental accrual by $6 million, which is included as discontinued operations in the Company's Consolidated Statements of Income and Comprehensive Income (See Note 19E).

4. Acquisitions and Business Combinations

A. Progress Telecommunications Corporation

In December 2003, Progress Telecommunications Corporation (PTC) and Caronet, Inc. (Caronet), both wholly-owned subsidiaries of Progress Energy, and EPIK Communications, Inc. (EPIK), a wholly-owned subsidiary of Odyssey Telecorp, Inc. (Odyssey), contributed substantially all of their assets and transferred certain liabilities to Progress Telecom, LLC (PTC LLC), a subsidiary of PTC. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash and Caronet become a wholly-owned subsidiary of Odyssey. Following consummation of all the transactions described above, PTC holds a 55% ownership interest in, and is the parent of PTC LLC. Odyssey holds a combined 45% ownership interest in PTC LLC through EPIK and Caronet. The accounts of PTC LLC are included in the Company's Consolidated Financial Statements since the transaction date. The minority interest is included in other liabilities and deferred credits in the Company's Consolidated Balance Sheets.

The transaction was accounted for as a partial acquisition of EPIK through the issuance of the stock of a consolidated subsidiary. The contributions of PTC's and Caronet's net assets were recorded at their carrying values of approximately $31 million. EPIK's contribution was recorded at its estimated fair value of $22 million using the purchase method, and was initially allocated as follows: property and equipment - $27 million; other current assets - $9 million; current liabilities - $21 million; and goodwill - $7 million. The goodwill was assigned to the Company's Other business segment and will not be deductible for tax purposes. The purchase price allocation is a preliminary estimate, based on available information, internal estimates and certain assumptions management believes are reasonable. Accordingly, the purchase price allocation is subject to finalization in 2004 pending the completion of internal and external appraisals of assets acquired. No gain or loss was recognized on the transaction. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for the years ended December 31, 2003 or 2002.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels Corporation entered into several independent transactions to acquire approximately 200 natural gas-producing wells with proven reserves of approximately 190 billion cubic feet (Bcf) from Republic Energy, Inc. and three other privately-owned companies, all headquartered in Texas. The total cash purchase price for the transactions was $168 million.

C. Westchester Acquisition

In April 2002, Progress Fuels acquired 100% of Westchester Gas Company (Westchester). The acquisition included approximately 215 natural gas-producing wells, 52 miles of intrastate gas pipeline and 170 miles of gas-gathering systems located within a 25-miles radius of Jonesville, Texas, on the Texas-Louisiana border.

The aggregate purchase price of approximately $153 million consisted of cash consideration of approximately $22 million and the issuance of 2.5 million shares of Progress Energy common stock valued at approximately $129 million. The purchase price included approximately $2 million of direct transaction costs. The final purchase price was allocated to oil and gas properties, intangible assets, diversified business property, net working capital and deferred tax liabilities for approximately $152 million, $9 million, $32 million, $5 million and $45 million, respectively. The $9 million intangible asset recorded relates to customer contracts acquired as part of the acquisition and are being amortized over their respective lives (See Note 8).

The acquisition was accounted for using the purchase method of accounting and, accordingly, the results of operations for Westchester have been included in the Company's Consolidated Financial Statements since the date of acquisition. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for the years ended December 31, 2002.

5. Property, Plant and Equipment

A. Utility Plant

The balances of utility plant in service at December 31 are listed below, with a range of depreciable lives for each:

(in millions)	**2003**	2002
Production plant (7-33 years)	**$ 3,821**	$ 3,433
Transmission plant (30-75 years)	**1,012**	976
Distribution plant (12-50 years)	**2,894**	2,728
General plant and other (8-75 years)	**423**	340
Utility plant in service	**$ 8,150**	$ 7,477

Substantially all of the electric utility plant is pledged as collateral for the first mortgage bonds of PEF (See Note 11).

Allowance for funds used during construction (AFUDC) represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the utilities over the service life of the property. The composite AFUDC rate for PEF's electric utility plant was 7.8% in 2003 and 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3% in 2003 and 2002. The depreciation provisions related to utility plant were $172 million and $162 million in 2003 and 2002, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D) and regulatory approved expenses (See Note 7).

Amortization of nuclear fuel costs, for the years ended December 31, 2003 and 2002 were $31 million and $32 million, respectively.

B. Diversified Business Property

The following is a summary of diversified business property at December 31, with a range of depreciable lives for each:

(in millions)	**2003**	2002
Equipment (3 – 25 years)	**$ 283**	$ 329
Land and mineral rights	**80**	76
Buildings and plants (5 – 40 years)	**99**	91
Oil and gas properties (units-of-production)	**412**	265
Telecommunications equipment (5 – 20 years)	**63**	41
Rail equipment (3 – 20 years)	**131**	54
Marine equipment (3 – 35 years)	**83**	81
Computers, office equipment and software (3 – 10 years)	**33**	30
Construction work in progress	**18**	34
Accumulated depreciation	**(361)**	(302)
Diversified business property, net	**$ 841**	$ 699

Diversified business depreciation expense was $92 million and $66 million for the years ended December 31, 2003 and 2002, respectively. The synthetic fuel facilities are being depreciated through 2007 when the Section 29 tax credits will expire.

C. Joint Ownership of Generating Facilities

PEF is entitled to shares of the generating capability and output of Crystal River Unit No. 3 (CR3) equal to its ownership interest. PEF also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. PEF's share of expenses for the jointly-owned facility is included in the appropriate expense category. The co-owner of Intercession City Unit P-11 (P11) has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEF's ownership interest in CR3 and P11 is listed below with related information at December 31, ($ in millions):

Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
2003				
Crystal River Unit No. 3	**91.78%**	**$ 875**	**$ 441**	**$ 49**
Intercession City Unit P-11	**66.67%**	**22**	**6**	**6**
2002				
Crystal River Unit No. 3	91.78%	$ 777	$ 375	$ 28
Intercession City Unit P-11	66.67%	22	5	4

D. Decommissioning, Dismantlement and Cost of Removal Provisions

PEF's nuclear plant depreciation expenses include a provision for future decommissioning costs, which are recoverable through rates charged to customers. In January 2002, PEF received regulatory approval from the FPSC to decrease its retail provision for nuclear decommissioning from approximately $21 million annually to approximately $8 million annually, effective January 2001. As a result of the settlement in the PEF rate case, PEF suspended accruals on its reserves for retail nuclear decommissioning through December 2005.

The accrual for retail fossil dismantlement reserves was suspended in 2002 by the Florida Rate Case settlement (See Note 7B).

PEF's cost of removal provisions, which are included in depreciation and amortization expense, were $72 million and $68 million in 2003 and 2002, respectively. These amounts represent the expense recognized for the disposal or removal of utility assets. The FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), that changed the accounting for the decommissioning, dismantlement and cost of removal provisions (See Note 5F).

E. Insurance

PEF is a member of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, PEF is insured for $500 million at its nuclear plant, CR3. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with a limit of $1.1 billion.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. PEF is insured thereunder, following a twelve-week deductible period, for 52 weeks in the amount of $4.5 million per week at CR3. An additional 110 weeks of coverage is provided at 80% of the above weekly amount. For the current policy period, PEF is subject to retrospective premium assessments of up to approximately $6 million with respect to the primary coverage, $6 million with respect to the decontamination, decommissioning and excess property coverage, and $5 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the U.S. Nuclear Regulatory Commission, PEF's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. PEF is responsible to the extent losses may exceed limits of the coverage described above.

PEF is insured against public liability for a nuclear incident up to $10.9 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, PEF, as an owner of a nuclear unit, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), PEF would be subject to pro rata assessments of up to $101 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. Congress is expected to approve revisions to the Price Anderson Act during 2004, that could include increased limits and assessments per reactor owned. The final outcome of this matter cannot be predicted at this time.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.2 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to the terrorist acts aggregate.

PEF self-insures its transmission and distribution lines against loss due to storm damage and other natural disasters. Pursuant to a regulatory order, PEF is accruing $6 million annually to a storm damage reserve and may defer any losses in excess of the reserve

(See Note 7A).

F. Asset Retirement Obligations

SFAS No. 143, "Accounting for Asset Retirement Obligations," provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was adopted by the Company effective January 1, 2003. This statement requires that the present value of retirement costs for which the Company has a legal obligation be recorded as a liability with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Cumulative accretion and accumulated depreciation were recognized for the time period from the date the liability would have been recognized had the provisions of this statement been in effect, to the date of adoption of this statement.

Upon adoption of SFAS No. 143, PEF recorded asset retirement obligations (AROs) totaling $303 million for nuclear decommissioning of irradiated plant. PEF used an expected cash flow approach to measure these obligations. This amount includes accruals recorded prior to adoption totaling $284 million, which were previously recorded in cost of removal. The related asset retirement costs, net of accumulated depreciation, recorded upon adoption totaled $39 million for regulated operations. The cumulative effect of adoption of this statement had no impact on the income of PEF, as the effects were offset by the establishment of a regulatory liability in the amount of $20 million, pursuant to SFAS No. 71. The regulatory liability represents the amount by which previously recorded accruals exceeded the cumulative accretion and accumulated depreciation for the time period from the date the liability would have been recognized had the provisions of this statement been in effect to the date of adoption.

The asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $37 million for regulated operations at December 31, 2003. The ongoing expense differences between SFAS No. 143 and regulatory cost recovery are being deferred to the regulatory liability.

Funds set aside in PEF's nuclear decommissioning trust fund for the nuclear decommissioning liability totaled $433 million at December 31, 2003 and $374 million at December 31, 2002. Net unrealized gains on the nuclear decommissioning trust fund were included in regulatory liabilities in 2003 and cost of removal in 2002.

The Company also recorded AROs totaling $10 million for coal mine operations, synthetic fuel operations and gas production of Progress Fuels Corporation. The Company used an expected cash flow approach to measure these obligations. This amount includes accruals recorded prior to adoption totaling $5 million, which were previously recorded in other liabilities and deferred credits. The related asset retirement costs, net of accumulated depreciation, recorded upon adoption totaled $3 million for nonregulated operations. The cumulative effect of initial adoption of this statement related to nonregulated operations was $2 million of pre-tax expense, which is included in other, net on the Company's Consolidated Statements of Income and Comprehensive Income for the year ended December 31, 2003.

The Company's AROs for coal mine operations, synthetic fuel operations and gas production of Progress Fuels Corporation totaled $20 million at December 31, 2003. The related asset retirement costs, net of accumulated depreciation, totaled $4 million for nonregulated operations at December 31, 2003. The following table shows the changes to the asset retirement obligations during the year ended December 31, 2003. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels Corporation.

(in millions)	Regulated	Nonregulated
Asset retirement obligations as of January 1, 2003	$ 303	$ 10
Additions	-	11
Accretion Expense	16	1
Deductions	-	(2)
Asset retirement obligations as of December 31, 2003	$ 319	$ 20

Pro forma net income has not been presented for prior years because the pro forma application of SFAS No. 143 to prior years would result in pro forma net income not materially different from the actual amounts reported.

The Company has identified but not recognized ARO liabilities related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by the Company. These easements are generally perpetual and only require retirement action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements, as the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

PEF previously recognized removal, decommissioning and dismantlement costs as a component of accumulated depreciation in accordance with regulatory treatment. At December 31, 2003, such costs totaling $1,175 million were included in regulatory liabilities on the Balance Sheets and consist of removal costs of $970 million, decommissioning costs for non-irradiated areas at nuclear facilities of $62 million and amounts previously collected for dismantlement of fossil generation plants of $143 million. At December 31, 2002, such costs totaling $1,452 million were included in cost of removal on the Balance Sheets and consist of removal costs of $913 million, removal costs for both the irradiated and non-irradiated areas at nuclear facilities of $397 million and amounts previously collected for dismantlement of fossil generation plants of $142 million. With the adoption of SFAS No. 143 in 2003, removal costs related to the irradiated areas at nuclear facilities are reported as asset retirement obligations on the 2003 Balance Sheets.

In January 2003, the Staff of the FPSC issued a notice of proposed rule development to adopt provisions relating to accounting for AROs under SFAS No. 143. Accompanying the notice was a draft rule presented by the Staff which adopts the provisions of SFAS No. 143 along with the requirement to record the difference between amounts prescribed by the FPSC and those used in the application of SFAS No. 143 as regulatory assets or regulatory liabilities, which was accepted by all parties. The Commission approved this draft rule and a final order was issued in the third quarter of 2003. Therefore, the adoption of the statement had no impact on the income of PEF due to the establishment of a regulatory liability pursuant to SFAS No. 71.

6. Inventory

At December 31, inventory was comprised of the following:

	Florida Progress		Progress Energy Florida	
(in millions)	**2003**	2002	**2003**	2002
Fuel	**$ 126**	$ 183	**$ 90**	$ 111
Rail equipment and parts	**132**	155	**-**	-
Materials and supplies	**154**	134	**140**	124
Other	**10**	20	**-**	-
Total inventory	**$ 422**	$ 492	**$ 230**	$ 235

7. Regulatory Matters

A. Regulatory Assets and Liabilities

As a regulated entity, PEF is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, PEF records certain assets and liabilities resulting from the effects of the ratemaking process, which would not be recorded under GAAP for nonregulated entities. The utility's ability to continue to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applied to PEF's operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, these factors could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

PEF has regulatory assets (liabilities) at December 31 as follows:

(in millions)	**2003**	2002
Deferred fuel cost	**$ 204**	$ 38
Income taxes recoverable through future rates (Note 13)	**42**	33
Deferred purchased power contract termination costs	**-**	47
Loss on reacquired debt (Note 1C)	**33**	20
Other	**51**	30
Total long-term regulatory assets	**126**	130
Non-ARO cost of removal (Note 5F)	**(1,175)**	-
Deferred impact of ARO (Note 5F)	**(8)**	-
Net nuclear decommissioning trust unrealized gains (Note 5F)	**(105)**	-
Storm reserve (Note 5E)	**(41)**	(36)
Other	**(19)**	(25)
Total long-term regulatory liabilities	**(1,348)**	(61)
Net regulatory assets (liabilities)	**$ (1,018)**	$ 107

Except for portions of deferred fuel, all assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. The utility expects to fully recover these assets and refund the liabilities through customer rates under current regulatory practice.

The Tiger Bay regulatory asset, for contract termination costs, is recovered pursuant to an agreement between PEF and several intervening parties, which was approved by the FPSC in June 1997. The amortization of the regulatory asset is calculated using revenues collected under the fuel adjustment clause as if the purchased power agreements related to the facility were still in effect, less the actual fuel costs and the related debt interest expense. Under the plan, PEF had the option to accelerate the amortization at its discretion. Including accelerated amounts, PEF recorded amortization expense of $47 million and $49 million in 2003 and 2002, respectively. By fourth quarter 2003 the regulatory asset was fully amortized.

In compliance with a regulatory order, PEF accrues a reserve for maintenance and refueling expenses anticipated to be incurred during scheduled nuclear plant outages.

B. Retail Rate Matters

PEF's retail rates are set by the FPSC, while its wholesale rates are governed by the FERC. The FPSC initiated a rate proceeding in 2001 regarding PEF's future base rates. In March 2002, the parties in PEF's rate case entered into a Stipulation and Settlement Agreement (the Agreement) related to retail rate matters. The Agreement was approved by the FPSC in April 2002. The Agreement is generally effective from May 2002 through December 2005; provided, however, that if PEF's base rate earnings fall below a 10% return on equity, PEF may petition the FPSC to amend its base rates.

The Agreement provides that PEF will reduce its retail revenues from the sale of electricity by an annual amount of $125 million. The Agreement also provides that PEF will operate under a Revenue Sharing Incentive Plan (the Plan) through 2005, and thereafter until terminated by the FPSC, that establishes annual revenue caps and sharing thresholds. The Plan provides that retail base rate revenues between the sharing thresholds and the retail base rate revenue caps will be divided into two shares – a 1/3 share to be received by PEF's shareholders, and a 2/3 share to be refunded to PEF's retail customers; provided, however, that for the year 2002 only, the refund to customers was limited to 67.1% of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for 2003 and 2002 were $1,333 million and $1,296 million, respectively, and will increase $37 million each year thereafter. The Plan also provides that all retail base rate revenues above the retail base rate revenue caps established for each year will be refunded to retail customers on an annual basis. For 2002, the refund to customers was limited to 67.1% of the retail base rate revenues that exceeded the 2002 cap. The retail base revenue cap for 2003 and 2002 was $1,393 million and $1,356 million, respectively, and will increase $37 million each year thereafter. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2003, $17 million has been accrued and will be refunded to customers by March 2004. Approximately $5 million was originally returned in March 2003 related to 2002 revenue sharing. However, in February 2003, the parties to the Agreement filed a motion seeking an order from the FPSC to enforce the Agreement. In this motion, the parties disputed PEF's calculation of retail revenue subject to refund and contended that the refund should be approximately $23 million. In July 2003, the FPSC ruled that PEF must provide an additional $18 million to its retail customers related to the 2002 revenue sharing calculation. PEF recorded this refund in the second quarter of 2003 as a charge against electric operating revenue and refunded this amount by October 2003.

The Agreement also provides that beginning with the in-service date of PEF's Hines Unit 2 and continuing through December 2005, PEF will be allowed to recover through the fuel cost recovery clause a return on average investment and depreciation expense for Hines Unit 2, to the extent such costs do not exceed the Unit's cumulative fuel savings over the recovery period. Hines Unit 2 is a 516 MW combined-cycle unit that was placed in service in December 2003.

PEF suspended retail accruals on its reserves for nuclear decommissioning and fossil dismantlement through December 2005. Additionally, for each calendar year during the term of the Agreement, PEF will record a $63 million depreciation expense reduction, and may, at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement. In 2003, PEF recorded $16 million of accelerated amortization of a regulatory liability related to a settled tax matter. There was no accelerated depreciation or amortization expense recorded for the year ended December 31, 2002.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expects to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level is not achieved for calendar years 2004 or 2005, PEF will provide a refund of $3 million for each year the level is not achieved to 10% of its total retail customers served by its worst performing distribution feeder lines.

The Agreement also provided that PEF was required to refund to customers $35 million of revenues PEF collected during the interim period since March 2001. This one-time retroactive revenue refund was recorded in the first quarter of 2002 and was returned to retail customers by December 2002. Any additional refunds under the Agreement are recorded when they become probable.

In February 2003, PEF petitioned the FPSC to increase its fuel factors due to continuing increases in oil and natural gas commodity prices. In March 2003, the FPSC approved PEF's petition and new rates became effective. In September 2003, PEF asked the FPSC to approve a cost adjustment in its annual fuel filing, primarily related to rising costs of fuel that will increase retail customer bills beginning January 2004. The total amount of the fuel adjustment requested above current levels was $322 million. In November 2003 the FPSC approved PEF's request and new rates became effective January 2004.

C. Regional Transmission Organizations and Standard Market Design

In 2000, the FERC issued Order No. 2000 on Regional Transmission Organizations (RTOs), which set minimum characteristics and eight functions for transmission entities, including independent system operators and transmission companies that are required to become FERC-approved RTOs. As a result of Order 2000, PEF, along with Florida Power & Light Company and Tampa Electric Company, filed and received provisional approval from the FERC, for a GridFlorida RTO. However, in July 2001, the FERC issued orders recommending that companies in the Southeast engage in mediation to develop a plan for a single RTO for the Southeast. PEF participated in the mediation. The FERC has not issued an order specifically on this mediation.

In July 2002, FERC issued its Notice of Proposed Rulemaking in Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). If adopted as proposed, the rules set forth in the SMD NOPR would materially alter the manner in which transmission and generation services are provided and paid for. PEF filed comments in November 2002 and supplement comments in January 2003. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provides an overview of what the FERC currently intends to include in a final rule in the SMD NOPR docket. The White Paper retains the fundamental and most protested aspects of SMD NOPR, including mandatory RTOs and the FERC's assertion of jurisdiction over certain aspects of retail service. FERC has not yet issued a final rule on SMD NOPR.

PEF has $4 million invested GridFlorida at December 31, 2003. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, PEF cannot predict the effect on future results of operations, cash flows or financial condition. Furthermore, the SMD NOPR presents several uncertainties, including what percentage of the investment in GridFlorida will be recovered, how the elimination of transmission charges, as proposed in the SMD NOPR, will impact PEF, and what amount of capital expenditures will be necessary to create a new wholesale market

8. Goodwill and Other Intangible Assets

Effective January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement clarifies the criteria for recording of other intangible assets separately from goodwill. Effective January 1, 2002, goodwill was no longer subject to amortization over its estimated useful life. Instead, goodwill is subject to at least an annual assessment for impairment which could result in periodic impairment charges.

The Company's carrying amount of goodwill at December 31, 2003 was $10 million and at December 31, 2002 was $11 million, in the Fuels segment. In December 2003, $7 million in goodwill was acquired as part of the PTC business combination and is in the Other segment (See Note 4A). The Company completed the annual goodwill impairment test for the Fuels segment in the second quarter of 2003, which indicated that the Company's goodwill was not impaired. The first annual test for the Other segment will be performed in 2004, since the goodwill was acquired in 2003. PEF has no goodwill at December 31, 2003 or 2002.

The Company has $9 million of net intangible assets at December 31, 2003 and no significant intangible assets at December 31, 2002. The $9 million arose from the final purchase price allocation for a contract acquired as part of the Westchester acquisition net of amortization to date (See Note 4C). PEF has no significant intangible assets at December 31, 2003 or 2002.

9. Impairment of Long-Lived Assets and Investments

Effective January 1, 2002, the Company adopted SFAS No. 144, which provides guidance for the accounting and reporting of impairment or disposal of long-lived assets. The statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." In 2003 and 2002, the Company recorded impairments and other charges of approximately $15 million and $300 million, respectively.

Due to the reduction in coal production at the Kentucky May Coal Mine, the Company evaluated its long-lived assets in 2003. Fair value was determined based on discounted cash flows. As a result of this review, the Company recorded asset impairments of $15 million on a pre-tax basis during the fourth quarter of 2003.

The 2002 amount includes an estimated impairment of assets held for sale of $67 million related to Railcar, Ltd. (See Note 3B). In 2002, the Company also initiated an independent valuation study to assess the recoverability of the long-lived assets of PTC. Based on this assessment, the Company recorded asset impairments of $215 million on a pre-tax basis and other charges of $18 million on a pre-tax basis in the third quarter of 2002. This write-down constitutes a significant reduction in the book value of these long-lived assets. The long-lived asset impairments include an impairment of property, plant and equipment, construction work in process and intangible assets. The impairment charge represents the difference between the fair value and carrying amount of these long-lived assets. The fair value of these assets was determined using a valuation study heavily weighted on the discounted cash flow methodology, using market approaches as supporting information.

10. Equity

A. Common and Preferred Stock

Common stock at December 31, 2003 and 2002 consisted of the following

(in millions except share data)	**2003**	2002
Florida Progress		
Common stock without par value, 250,000,000 shares authorized; 98,616,658 shares outstanding in 2003 and 2002	**$ 1,699**	$ 1,629
Progress Energy Florida		
Common stock without par value, 60,000,000 shares authorized; 100 shares outstanding in 2003 and 2002	**$ 1,081**	$ 1,081

From time-to-time the Company and its subsidiaries may receive equity contributions from and pay dividends to Progress Energy. The Company received equity contributions from Progress Energy of $168 million and $220 million during 2003 and 2002, respectively. The Company paid dividends to Progress Energy of $301 million and $303 million 2003 and 2002, respectively.

The authorized capital stock of the Company includes 10 million shares of preferred stock, without par value, including 2 million shares designated as Series A Junior Participating Preferred Stock. No shares of the Company's preferred stock are issued or outstanding.

The authorized capital stock of PEF includes three classes of preferred stock: 4 million shares of Cumulative Preferred Stock, $100 par value; 5 million shares of Cumulative Preferred Stock, without par value; and 1 million shares of Preference Stock, $100 par value. No shares of PEF's Cumulative Preferred Stock, without par value, or Preference Stock are issued or outstanding. All Cumulative Preferred Stock series are without sinking funds and are not subject to mandatory redemption. Preferred stock outstanding at December 31, 2003 and 2002 consisted of the following (in millions):

4.00% - 39,980 shares outstanding (redemption price $104.25)	$ 4
4.40% - 75,000 shares outstanding (redemption price $102.00)	8
4.58% - 99,990 shares outstanding (redemption price $101.00)	10
4.60% - 39,997 shares outstanding (redemption price $103.25)	4
4.75% - 80,000 shares outstanding (redemption price $102.00)	8
Total Preferred Stock of Florida Power Corporation	$ 34

B. Stock-Based Compensation

Employee Stock Ownership Plan

Progress Energy sponsors the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) for which substantially all full-time non-bargaining unit employees and certain part-time non-bargaining employees within participating subsidiaries are eligible. Effective January 1, 2002, Florida Progress is a participating subsidiary of the 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common stock needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to Progress Energy matching and incentive contributions and/or reinvested dividends.

Florida Progress' matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. The 401(k) common stock share needs are met with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year; while costs for the matching component are typically met with shares in the same year incurred. Florida Progress' matching and incentive cost which was and will be met with shares released from the suspense account totaled approximately $4 million and $2 million for the year ended December 31, 2003 and 2002, respectively. Matching and incentive costs totaled approximately $11 million and $10 million for the years ended December 31, 2003 and 2002, respectively.

Stock Option Agreements

Pursuant to the Progress Energy's 1997 Equity Incentive Plan and 2002 Equity Incentive Plans as amended and restated as of July 10, 2002, Progress Energy may grant options to purchase shares of common stock to directors, officers and eligible employees. For the years ended December 31, 2003 and 2002 approximately 3.0 million and 2.9 million common stock options were granted, respectively. Of these amounts, approximately 1.0 million and 0.8 million options, respectively, were granted to officers and eligible employees of Florida Progress and PEF in 2003, approximately 0.5 million and 0.4 million options, respectively, were granted in 2002.

Other Stock-Based Compensation Plans

Progress Energy has additional compensation plans for officers and key employees that are stock-based in whole or in part. The Company participates in these plans. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards program (RSA), both of which were established pursuant to Progress Energy's 1997 Equity Incentive Plan and were continued under the 2002 Equity Incentive Plan, as amended and restated as of July 10, 2002.

Under the terms of the PSSP, officers and key employees are granted performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy's common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on Progress Energy's results as compared to a peer group of utilities. Compensation expense is recognized over the vesting period based on the expected ultimate cash payout and is reduced by any forfeitures.

The RSA program allows Progress Energy to grant shares of restricted common stock to officers and key employees of Progress Energy. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period and is reduced by any forfeitures.

The total amount expensed by the Company for other stock-based compensation under these plans was $9 million and $5 million in 2003 and 2002, respectively.

C. Accumulated Other Comprehensive Loss

Changes in comprehensive income, net of tax, for PEF are as follows for the years ended December 31:

(in millions)	**2003**	2002
Net Income	**$ 297**	$ 325
Minimum pension liability adjustment (net of tax of $1 and $1, respectively)	**(1)**	(3)
Comprehensive Income	**$ 296**	$ 322

Components of accumulated other comprehensive loss for Florida Progress and PEF at December 31, are as follows:

(in millions)	Florida Progress		Progress Energy Florida	
	2003	2002	**2003**	2002
Loss on cash flow hedges	**$ (8)**	$ (6)	**$ -**	$ -
Minimum pension liability adjustments	**(8)**	(5)	**(4)**	(3)
Foreign currency translation and other	**(1)**	(5)	**-**	-
Total accumulated other comprehensive loss	**$ (17)**	$ (16)	**$ (4)**	$ (3)

11. Debt and Credit Facilities

A. Debt and Credit

At December 31, the Company's (including PEF) long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2003):

(in millions)		**2003**	2002
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2004-2033	5.60%	**$ 1,330**	$ 810
Pollution control revenue bonds, maturing 2018-2027	1.04%	**241**	241
Medium-term notes, maturing 2004-2028	6.75%	**379**	417
Unamortized premium and discount, net		**(3)**	(7)
		1,947	1,461
Florida Progress Funding Corporation			
Debt to affiliated trust, maturing 2039	7.10%	**309**	-
Mandatorily redeemable preferred securities, maturing 2039		**-**	300
		309	300
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2004-2008	6.78%	**165**	223
Unsecured note with parent, maturing 2011	6.43%	**500**	500
Miscellaneous notes		**1**	1
		666	724
Less: Current portion of long-term debt		**(68)**	(275)
Total Long-Term Debt, Net		**$ 2,854**	$ 2,210

At December 31, 2003, PEF had committed lines of credit which are used to support its commercial paper borrowings and had no outstanding loans. PEF is required to pay minimal annual commitment fees to maintain its credit facilities. The following table summarizes PEF's credit facilities (in millions):

Description	Total
364-Day (expiring 3/31/04)	$ 200
3-Year (expiring 4/1/06)	200
	$ 400

At December 31, 2003, PEF had no outstanding commercial paper and other short-term debt classified as short-term obligations. At December 31, 2002, PEF had $257 million of outstanding commercial paper and other short-term debt classified as short-term obligations. The weighted-average interest rate of such short-term obligations at December 31, 2002 was 1.55%.

The combined aggregate maturities of Florida Progress long-term debt for 2004 through 2008 are approximately, in millions, $68,

$49, $109, $124 and $127, respectively. PEF's aggregate maturities of long-term debt for 2004 through 2008 are approximately, in millions, $43, $48, $48, $89 and $82, respectively.

B. Covenants and Default Provisions

Financial Covenants
PEF's credit line contains various terms and conditions that could affect PEF's ability to borrow under these facilities. These include a maximum debt to total capital ratio, an interest test, a material adverse change clause and a cross-default provision.

PEF's credit line requires a maximum total debt to total capital ratio of 65.0%. Indebtedness as defined by the bank agreement includes certain letters of credit and guarantees which are not recorded on the Balance Sheets. At December 31, 2003, PEF's total debt to total capital ratio was 51.5%.

PEF's 364-day and 3-year credit facility have a financial covenant for interest coverage. The covenant requires PEF's EBITDA to interest expense to be at least 3 to 1. For the year ended December 31, 2003, this ratio was 9.22 to 1.

Material Adverse Change Clause
The credit facility of PEF includes a provision under which lenders could refuse to advance funds in the event of a material adverse change in the borrower's financial condition.

Default Provisions
PEF's credit lines include cross-default provisions for defaults of indebtedness in excess of $10 million. PEF's cross-default provisions only apply to defaults of indebtedness by PEF and not to other affiliates of PEF. The credit lines of Progress Energy include a similar provision. Progress Energy's cross-default provisions only apply to defaults of indebtedness by Progress Energy and its significant subsidiaries, which includes PEF, Florida Progress, Progress Fuels and Progress Capital.

In the event that either of these cross-default provisions were triggered, the lenders could accelerate payment of any outstanding debt. Any such acceleration would cause a material adverse change in the respective company's financial condition. Certain agreements underlying the Company's indebtedness also limit the Company's ability to incur additional liens or engage in certain types of sale and leaseback transactions.

Other Restrictions
PEF's mortgage indenture provides that it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943.

In addition, PEF's Articles of Incorporation provide that no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceed (a) all credits to retained earnings since April 30, 1944, plus (b) all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers amounts from retained earnings to capital surplus. At December 31, 2003, none of PEF's retained earnings was restricted.

PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75% of net income available for dividends if common stock equity falls below 25% of total capitalization, and to 50% if common stock equity falls below 20%. On December 31, 2003, PEF's common stock equity was approximately 52.5% of total capitalization.

C. Secured Obligations

PEF's first mortgage bonds are secured by their respective mortgage indentures. PEF's mortgage constitutes a first lien on substantially all of its fixed properties, subject to certain permitted encumbrances and exceptions. The PEF mortgage also constitutes a lien on subsequently acquired property. At December 31, 2003, PEF had approximately $1,571 million in aggregate principal amount of first mortgage bonds outstanding including those related to pollution control obligations. The PEF mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

Florida Progress has fully guaranteed the outstanding debt obligations for Progress Capital, a wholly-owned subsidiary of Florida Progress. At December 31, 2003 and 2002, Progress Capital had $165 million and $223 million, respectively; in medium term notes outstanding which are recorded on the Company's Consolidated Balance Sheets.

E. Hedging Activities

PEF uses interest rate derivatives to adjust the fixed and variable rate components of its debt portfolio and to hedge cash flow risk of fixed rate debt to be issued in the future. See discussion of risk management and derivative transactions at Note 15.

F. Company-Obligated Mandatorily Redeemable Cumulative Quarterly Income Preferred Securities of an Unconsolidated Subsidiary Trust Holding Solely Florida Progress Guaranteed Subordinated Deferrable Interest Notes

In April 1999, FPC Capital I (the Trust), an indirect wholly-owned subsidiary of FPC, issued 12 million shares of $25 par cumulative FPC-obligated mandatorily redeemable preferred securities (Preferred Securities) due 2039, with an aggregate liquidation value of $300 million and an annual distribution rate of 7.10%. Prior to the adoption of FIN No. 46, the Company consolidated the Trust, which holds the Preferred Securities. The Trust is a special-purpose entity, and therefore the Company applied FIN No. 46 to the Trust at December 31, 2003 (See Note 2). The adoption of FIN No. 46 required the Company to deconsolidate the Trust at December 31, 2003.

The existence of the Trust is for the sole purpose of issuing the Preferred Securities and the common securities and using the proceeds thereof to purchase from Florida Progress Funding Corporation (Funding Corp.) its 7.10% Junior Subordinated Deferrable Interest Notes (subordinated notes) due 2039, for a principal amount of $309 million. The subordinated notes and the Notes Guarantee (as discussed below) are the sole assets of the Trust. Funding Corp.'s proceeds from the sale of the subordinated notes were advanced to Progress Capital and used for general corporate purposes including the repayment of a portion of certain outstanding short-term bank loans and commercial paper.

FPC has fully and unconditionally guaranteed the obligations of Funding Corp. under the subordinated notes (the Notes Guarantee). In addition, FPC has guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by FPC of the Trust's obligations under the Preferred Securities.

The subordinated notes may be redeemed at the option of Funding Corp. beginning in 2004 at par value plus accrued interest through the redemption date. The proceeds of any redemption of the subordinated notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

Prior to December 2003, these Preferred Securities were classified as long-term debt on the Company's Consolidated Balance Sheets. After deconsolidation of the Trust at December 31, 2003, FPC's subordinated notes payable to the Trust are classified as affiliate long-term debt on the Company's December 31, 2003 Consolidated Balance Sheet.

12. Fair Value of Financial Instruments

At December 31, 2003 and 2002, there were miscellaneous investments, consisting primarily of investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $66 million and $64 million, respectively, included in miscellaneous other property and investments. At PEF, these investments had carrying amounts of $33 million at December 31, 2003 and 2002. The carrying amount of these investments approximates fair value due to the short maturity. The carrying amount of the Company's long-term debt, including current maturities, was $2,922 million and $2,485 million at December 31, 2003 and 2002, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3,105 million and $2,654 million at December 31, 2003 and 2002, respectively. The carrying amount of PEF's long-term debt, including current maturities, was $1,947 million and $1,461 million at December 31, 2003 and 2002, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2,061 million and $1,592 million at December 31, 2003 and 2002, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning. These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. Nuclear decommissioning trust funds are presented on the Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments.

13. Income Taxes

Deferred income taxes are provided for temporary differences between book and tax bases of assets and liabilities. Investment tax credits related to regulated operations are amortized over the service life of the related property. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by PEF through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the utilities pursuant to rate orders.

Net Accumulated deferred income tax assets (liabilities) at December 31 are (in millions):

Florida Progress	**2003**	2002
Accumulated depreciation and property cost differences	**$ (349)**	$ (385)
Deferred costs, net	**2**	5
Federal income tax credit carry forward	**436**	314
Miscellaneous other temporary differences, net	**125**	125
Valuation allowance	**(29)**	(26)
Net accumulated deferred income tax asset	**$ 185**	$ 33

Progress Energy Florida	**2003**	2002
Accumulated depreciation and property cost differences	**$ (354)**	$ (377)
Deferred costs, net	**(22)**	(6)
Miscellaneous other temporary differences, net	**52**	48
Net accumulated deferred income tax liability	**$ (324)**	$ (335)

Florida Progress's total deferred income tax liabilities were $467 million and $484 million at December 31, 2003 and 2002, respectively. Total deferred income tax assets were $652 million and $517 million at December 31, 2003 and 2002, respectively. PEF's total deferred income tax liabilities were $396 million and $361 million at December 31, 2003 and 2002, respectively. Total deferred income tax assets were $72 million and $26 million at December 31, 2003 and 2002, respectively.

Florida Progress's federal income tax credit carry forward at December 31, 2003 consists of $429 million of alternative minimum tax credit with an indefinite carry forward period and $7 million of general business credit with a carry forward period that will begin to expire in 2022.

Florida Progress established additional valuation allowances of $3 million and $5 million during 2003 and 2002, respectively, due to the uncertainty of realizing certain future state tax benefits. The Company believes it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

Reconciliations of the Company's effective income tax rate to the statutory federal income tax rate are:

Florida Progress	**2003**	2002
Effective income tax rate	**(32.7)%**	(304.8)%
State income taxes, net of federal benefit	**(2.5)**	(10.3)
AFUDC amortization	**(0.7)**	(4.1)
Federal tax credits	**63.8**	311.3
Goodwill amortization and write-offs	**(0.5)**	-
Investment tax credit amortization	**1.8**	11.3
Progress Energy tax allocation benefit	**3.8**	35.2
Other differences, net	**2.0**	(3.6)
Statutory federal income tax rate	**35.0%**	35.0%

Progress Energy Florida	**2003**	2002
Effective income tax rate	**33.1%**	33.6%
State income taxes, net of federal benefit	**(3.5)**	(3.4)
Investment tax credit amortization	**1.4**	1.3
Progress Energy tax allocation benefit	**2.7**	3.8
Other differences, net	**1.3**	(0.3)
Statutory federal income tax rate	**35.0%**	35.0%

Income tax expense (benefit) applicable to continuing operations is comprised of (in millions):

Florida Progress	**2003**	2002
Current - federal	**$ 6**	$ 43
state	**18**	23
Deferred - federal	**(123)**	(220)
state	**(5)**	(13)
Investment tax credit	**(6)**	(6)
Total income tax expense (benefit)	**$ (110)**	$ (173)

Progress Energy Florida	**2003**	2002
Current - federal	**$ 145**	$ 172
state	**27**	29
Deferred - federal	**(16)**	(29)
state	**(3)**	(3)
Investment tax credit	**(6)**	(6)
Total income tax expense (benefit)	**$ 147**	$ 163

The Company and each of its wholly-owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 1C). The Company's intercompany tax payable was approximately $22 million and $33 million at December 31, 2003 and 2002, respectively. Progress Energy Florida's intercompany tax payable was approximately $20 million and $25 million at December 31, 2003 and 2002, respectively.

Florida Progress through its subsidiaries is a majority owner in three entities and a minority owner in three entities that own facilities that produce synthetic fuel as defined under the Internal Revenue Service Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 of the Code (Section 29) if certain requirements are satisfied, including a requirement that the synthetic fuel differs significantly in chemical composition from the coal used to produce such synthetic fuel and that the fuel was produced from a facility that was placed in service before July 1, 1998. Total Section 29 credits generated to date are approximately $787 million. All three majority-owned entities and all three minority-owned entities have received private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Should the tax credits be denied on future audits, and the Company fails to prevail through the IRS or legal process, there could be a significant tax liability owed for previously taken Section 29 credits, with a significant impact on earnings and cash flows.

One of the Company's synthetic fuel entities, Colona Synfuel Limited Partnership, L.L.L.P. (Colona), is being audited by the IRS. The audit of Colona was expected. The Company is audited regularly in the normal course of business as are most similarly situated companies. The Company has been allocated approximately $279 million in tax credits to date for this synthetic fuel entity.

In September 2002, all three of Florida Progress' majority-owned synthetic fuel entities, including Colona, and two of the Company's minority owned synthetic fuel entities were accepted into the IRS's Pre-Filing Agreement (PFA) program. The PFA program allows taxpayers to voluntarily accelerate the IRS exam process in order to seek resolution of specific issues. Either the Company or the IRS can withdraw from the program at any time, and issues not resolved through the program may proceed to the next level of the IRS exam process. While the ultimate outcome is uncertain, the Company believes that participation in the PFA program will likely shorten the tax exam process.

In June 2003, the Company was informed that IRS field auditors had raised questions regarding the chemical change associated with coal-based synthetic fuel manufactured at its Colona facility and the testing process by which the chemical change is verified. (The questions arose in connection with the Company's participation in the PFA program.) The chemical change and the associated testing process were described as part of the PLR request for Colona. Based on that application, the IRS ruled in Colona's PLR that the synthetic fuel produced at Colona undergoes a significant chemical change and thus qualifies for tax credits under Section 29.

In October 2003, the National Office of the IRS informed the Company that it had rejected the IRS field auditors' challenges regarding whether the synthetic fuel produced at the Company's Colona facility was the result of a significant chemical change. The National Office had concluded that the experts, engaged by Colona who test the synthetic fuel for chemical change, used reasonable scientific methods to reach their conclusions. Accordingly, the National Office will not take any adverse action on the PLR that has been issued for the Colona facility.

Although this ruling applies only to the Colona facility, the Company believes that the National Office's reasoning would be equally applicable to the other Progress Energy facilities. The Company applies essentially the same chemical process and uses the same independent laboratories to confirm chemical change in the synthetic fuel manufactured at each of its other facilities.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the Internal Revenue Service concerning their Colona synthetic fuel facilities. The Closing Agreement provided that the Colona facilities were placed in service before July 1, 1998, which is one of the qualification requirements for tax credits under Section 29 of the Internal Revenue Code. The Closing Agreement further provides that the fuel produced by the Colona facilities in 2001 is a "qualified fuel" for purposes of the Section 29 tax credits. This action concludes the IRS PFA program with respect to Colona.

Although the execution of the Colona Closing Agreement is a significant event, the audits of the Company's facilities are not yet completed and the PFA process continues with respect to the four synthetic fuel facilities owned by other affiliates of Progress Energy and FPC. Currently, the focus of that process is to determine that the facilities were placed in service before July 1, 1998. In management's opinion, Progress Energy is complying with all the necessary requirements to be allowed such credits under Section 29, although it cannot provide certainty, that it will prevail if challenged by the IRS on credits taken. Accordingly, the Company has no current plans to alter its synthetic fuel production schedule as a result of these matters.

In October 2003, the United States Senate Permanent Subcommittee on Investigations began a general investigation concerning synthetic fuel tax credits claimed under Section 29 of the Internal Revenue Code. The investigation is examining the utilization of the credits, the nature of the technologies and fuels created, the use of the synthetic fuel, and other aspects of Section 29 and is not specific to the Company's synthetic fuel operations. Progress Energy is providing information in connection with this investigation. The Company cannot predict the outcome of this matter.

14. Benefit Plans

The Company and some of its subsidiaries (including PEF) have a non-contributory defined benefit retirement (pension) plan for substantially all full-time employees. The Company also has supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, the Company and some of its subsidiaries (including PEF) provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. The Company uses a measurement date of December 31 for its pension and OPEB plans.

The components of the net periodic benefit cost for the years ended December 31 are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2003**	2002	**2003**	2002
Service cost	$ **21**	$ 19	$ **5**	$ 5
Interest cost	**46**	44	**16**	15
Expected return on plan assets	**(62)**	(76)	**(1)**	(1)
Net amortization	**3**	(7)	**5**	4
Net cost/(benefit) recognized by Florida Progress	$ **8**	$ (20)	$ **25**	$ 23
Net cost/(benefit) recognized by PEF	$ **5**	$ (22)	$ **24**	$ 22

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10% of the greater of the obligation or the market-related value of assets are amortized over the average remaining service period of active participants. The Company uses fair value for the market-related value of assets.

Reconciliations of the changes in the plans' benefit obligations and the plans' funded status are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2003**	2002	**2003**	2002
Obligation at January 1	$ **714**	$ 588	$ **236**	$ 180
Service cost	**21**	19	**5**	5
Interest cost	**46**	44	**15**	15
Benefit payments	**(41)**	(39)	**(15)**	(14)
Actuarial loss	**32**	119	**19**	55
Transfers	**-**	(18)	**-**	(5)
Obligation at December 31	**772**	713	**260**	236
Fair value of plan assets at December 31	**849**	687	**18**	16
Funded status	**77**	(26)	**(242)**	(220)
Unrecognized transition obligation	**-**	(1)	**31**	35
Unrecognized prior service cost (benefit)	**(18)**	(20)	**7**	7
Unrecognized net actuarial (gain) loss	**103**	213	**51**	33
Minimum pension liability adjustment	**(11)**	(7)	**-**	-
Prepaid (accrued) cost at December 31, net – Florida Progress	$ **151**	$ 159	$ **(153)**	$ (145)
Prepaid (accrued) cost at December 31, net – PEF	$ **183**	$ 188	$ **(148)**	$ (139)

The Florida Progress net prepaid pension cost of $151 million and $159 million at December 31, 2003 and 2002, respectively, is included in the Company's Consolidated Balance Sheets as prepaid pension cost of $223 million and $226 million, respectively, and accrued benefit cost of $72 million and $67 million, respectively, which is included in other liabilities and deferred credits. The PEF net prepaid pension cost of $183 million and $188 million at December 31, 2003 and 2002, respectively, is included in the Balance Sheets as prepaid pension cost of $220 million and $223 million, respectively, and accrued benefit cost of $37 million and $35 million, respectively, which is included in other liabilities and deferred credits. For Florida Progress, the defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $74 million and $68 million at December 31, 2003 and 2002, respectively. Those plans had accumulated benefit obligations totaling $73 million and $67 million, respectively, and no plan assets. For PEF, the defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $38 million and $35 million at December 31, 2003 and 2002, respectively. Those plans had accumulated benefit obligations totaling $37 million and $35 million, respectively, and no plan assets. For Florida Progress, the total accumulated benefit obligation for pension plans was $729 million and $662 million at December 31, 2003 and 2002, respectively. For PEF, the total accumulated benefit obligation for pension plans was $653 million and $592 million at December 31, 2003 and 2002, respectively. Accrued other postretirement benefit cost is included in other liabilities and deferred credits in the respective Balance Sheets of Florida Progress and PEF.

Florida Progress and PEF recorded a minimum pension liability adjustment of $11 million and $6 million, respectively, at December 31, 2003, with a corresponding pre-tax charge to accumulated other comprehensive loss, a component of common stock equity. Florida Progress and PEF recorded a minimum pension liability adjustment of $7 million and $4 million, respectively, at December 31, 2002, with a corresponding pre-tax charge to accumulated other comprehensive loss, a component of common stock equity.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2003**	2002	**2003**	2002
Fair value of plan assets January 1	**$ 687**	$ 854	**$ 16**	$ 13
Actual return on plan assets	**199**	(114)	**1**	1
Benefit payments	**(41)**	(39)	**(15)**	(14)
Employer contributions	**4**	4	**16**	16
Transfers	**-**	(18)	**-**	-
Fair value of plan assets at December 31	**$ 849**	$ 687	**$ 18**	$ 16

In the table above, substantially all employer contributions represent benefit payments made directly from Company assets. The remaining benefits payments were made directly from plan assets. The OPEB benefit payments represent the net Company cost after participant contributions. Participant contributions represent approximately 10% of gross benefit payments.

The asset allocation for the Company's plans at the end of 2003 and 2002 and the target allocation for the plans, by asset category, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End		Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2004	**2003**	2002	2004	**2003**	2002
Equity – domestic	50%	**49%**	47%	-	**-**	-
Equity – international	15%	**22%**	20%	-	**-**	-
Debt – domestic	15%	**11%**	15%	100%	**100%**	100%
Debt – international	10%	**11%**	10%	-	**-**	-
Other	10%	**7%**	8%	-	**-**	-
Total	100%	**100%**	100%	100%	**100%**	100%

With regard to its pension assets, the Company sets strategic allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, the Company employs external investment managers who have complementary investment philosophies and approaches. Tactical shifts (plus or minus five percent) in asset allocation from the strategic allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. The Company's OPEB assets are invested solely in fixed income securities.

In 2004, the Company expects to make required contributions of $1 million directly to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2004 through 2008 and in total for 2009-2013, in millions, are approximately $40, $41, $42, $44, $46 and $269, respectively. The expected benefit payments for the OPEB plan for 2004 through 2008 and in total for 2009-2013, in millions, are approximately $14, $15, $17, $18, $19 and $116, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from Company assets. The benefit payment amounts reflect the net cost to the Company after any participant contributions.

The following weighted-average actuarial assumptions were used in the calculation of the year-end obligation:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rate	**6.30%**	6.60%	**6.30%**	6.60%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	**-**	-
Non-bargaining	**-**	4.00%	**-**	-
Supplementary plans	**5.00%**	4.00%	**-**	-
Initial medical cost trend rate for pre-Medicare benefits	**-**	-	**7.25%**	7.50%
Initial medical cost trend rate for post-Medicare benefits	**-**	-	**7.25%**	7.50%
Ultimate medical cost trend rate	**-**	-	**5.25%**	5.25%
Year ultimate medical cost trend rate is achieved	**-**	-	**2009**	2009

The Company's primary defined benefit retirement plan for non-bargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4. Therefore, effective December 31, 2003, the Company began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan and will use that method to measure future benefit costs. Under the traditional unit credit method, no assumptions are included about future changes in compensation and the accumulated benefit obligation and projected benefit obligation are the same.

The following weighted-average actuarial assumptions were used in the calculation of the net periodic cost:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rate	**6.60%**	7.50%	**6.60%**	7.50%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	**-**	-
Non-bargaining and supplementary	**4.00%**	4.00%	**-**	-
Expected long-term rate of return on plan assets	**9.25%**	9.25%	**5.00%**	5.00%
Initial medical cost trend rate for pre-Medicare benefits	**-**	-	**7.50%**	7.50%
Initial medical cost trend rate for post-Medicare benefits	**-**	-	**7.50%**	7.50%
Ultimate medical cost trend rate	**-**	-	**5.25%**	5.00%
Year ultimate medical cost trend rate is achieved	**-**	-	**2009**	2008

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For pension plan assets, those benchmarks support an expected long-term rate of return between 9.5% and 10.0%. The Company has chosen to use an expected long-term rate of 9.25% due to the uncertainties of future returns. The OPEB expected long-term rate of return of 5.0% reflects that the OPEB assets are invested solely in fixed income securities.

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. Assuming a 1% increase in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2003 would increase by $1 million, and the OPEB obligation at December 31, 2003, would increase by $18 million. Assuming a 1% decrease in the medical cost trend rates, the aggregate of the service and interest cost components of the net periodic OPEB cost for 2003 would decrease by $1 million and the OPEB obligation at December 31, 2003, would decrease by $15 million.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. In accordance with guidance issued by the FASB in FASB Staff Position FAS 106-1, the Company has elected to defer accounting for the effects of the Act due to uncertainties regarding the effects of the implementation of the Act and the accounting for certain provisions of the Act. Therefore, OPEB information presented above and in the financial statements does not reflect the effects of the Act. When specific authoritative accounting guidance is issued, it could require plan sponsors to change previously reported information. The Company is in the early stages of reviewing the Act and determining its potential effects on the Company.

15. Risk Management Activities and Derivatives Transactions

Under its risk management policy, the Company may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. The Company minimizes such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential non-performance by counterparties is not expected to have a material effect on the consolidated financial position or consolidated results of operations of the Company.

A. Commodity Contracts – General

Most of the Company's commodity contracts either are not derivatives or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

B. Commodity Derivatives – Cash Flow Hedges

Progress Fuels held natural gas cash flow hedging instruments at December 31, 2003 and 2002. The objective for holding these instruments is to manage a portion of the market risk associated with fluctuations in the price of natural gas for Progress Fuel's forecasted sales. At December 31, 2003, Progress Fuels is hedging exposures to the price variability of natural gas through December 2005.

The total fair value of these instruments at December 31, 2003 and 2002 was a $14 million and a $10 million liability position, respectively. The ineffective portion of commodity cash flow hedges was not material in 2003 and 2002. At December 31, 2003, $8 million of after-tax deferred losses in accumulated other comprehensive income (OCI) are expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

C. Commodity Derivatives

Nonhedging derivatives, primarily electricity forward contracts, may be entered into for trading purposes and for economic hedging purposes. While management believes these derivatives mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. The Company manages open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material during 2003 or 2002, and the Company did not have material outstanding positions in such contracts at December 31, 2003 or 2002.

D. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

The Company manages its interest rate exposure in part by maintaining its variable-rate and fixed rate-exposures within defined limits. In addition, the Company also enters into financial derivative instruments, including, but not limited to, interest rate swaps and lock agreements to manage and mitigate interest rate risk exposure.

The Company uses cash flow hedging strategies to hedge variable interest rates on long-term debt and to hedge interest rates with regard to future fixed-rate debt issuances. PEF held no interest rate cash flow hedges at December 31, 2003. At December 31, 2002, PEF held an interest rate cash flow hedge, with a notional amount of $35 million, related to an anticipated 2003 issuance of long-term debt. The hedge was settled at the time of issuing the related debt. At December 31, 2003, an immaterial amount of after-tax deferred losses in OCI is expected to be reclassified to earnings during the next 12 months as the hedged interest payments occur.

The Company uses fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. At December 31, 2003 and 2002, the Company had no open interest rate fair value hedges.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates.

16. Related Party Transactions

The Company and its subsidiaries participate in money pools, operated by Progress Energy, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pools are also used to settle intercompany balances. The weighted-average interest rate for the money pools was 1.47% and 2.18% at December 31, 2003 and 2002, respectively. At December 31, 2003 and 2002, Florida Progress had $602 million and $380 million, respectively, and PEF had $363 million and $237 million, respectively, of amounts payable to the money pool that are included in notes payable to affiliated companies on the Balance Sheets. Net interest expense related to money pool borrowings was $5 million and $5 million for Florida Progress in 2003 and 2002 respectively. PEF recorded net interest expense of $2 million and $1 million related to the money pool for 2003 and 2002, respectively.

Progress Energy formed Progress Energy Service Company, LLC (PESC) to provide specialized services, at cost, to the Company and its subsidiaries, as approved by the U.S. Securities and Exchange Commission (SEC). The Company and its subsidiaries have an agreement with PESC under which services, including purchasing, information technology, telecommunications, marketing, treasury, human resources, accounting, real estate, legal and tax are rendered at cost. Amounts billed by PESC for these services during 2003 and 2002 to Florida Progress amounted to $190 million and $173 million, respectively, and amounts billed to PEF were $153 million and $161 million, respectively. At December 31, 2003 and 2002, Florida Progress had a net payable to PESC of $32 and $43 million, respectively. PEF had a net payable to PESC of $23 million and $37 million, respectively, at December 31, 2003 and 2002. During 2002, the Office of Public Utility Regulation within the SEC completed an audit examination of Progress Energy's books and records. This examination is a standard process for all PUHCA registrants. Based on the review, the method for allocating PESC costs to the Parent and its affiliates changed for 2003 and retroactive reallocations of 2002 and 2001 charges were made during the first quarter. The net after-tax impact of the reallocation of costs for 2002 and 2001 was an increase in expenses of $5 million at Florida Progress and a reduction of expenses at PEF by $1 million.

Progress Fuels has an outstanding note due to the Parent. The principal outstanding on this note was $500 million at December 31, 2003 and 2002. Progress Fuels recorded interest expense related to this note of $32 million for 2003 and 2002.

The Company has an outstanding note due to a related trust. The principal outstanding on this note was $309 million at December 31, 2003 (See Note 11F).

Progress Fuels sells coal to PEF which are eliminated from revenues in Florida Progress' Consolidated Financial Statements. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," profits on intercompany sales between Progress Fuels and PEF are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits for all the years presented were not significant.

In April 2000, Progress Ventures, Inc. (PVI), a wholly-owned subsidiary of Progress Energy, purchased a 90% interest in an affiliate of Progress Fuels that owns a synthetic fuel facility located at the Company-owned mine site in Virginia. In May 2000, PVI purchased a 90% ownership interest in another synthetic fuel facility located in West Virginia. The purchase agreements contained a provision that would require PVI to sell, and the respective Progress Fuels affiliate to repurchase, the 90% interest had the share exchange among Florida Progress, Progress Energy and CP&L not occurred. Progress Fuels has accounted for the transactions as a sale for tax purposes and, because of the repurchase obligation, as a financing for financial reporting purposes in the pre-acquisition period and as a transfer of assets within a controlled group as of the acquisition date. At the date of acquisition, assets of $8 million were transferred to Progress Energy. At December 31, 2003 and 2002, the Company has a note receivable of $38 million and $47 million from PVI that has been recorded as a reduction to equity for financial reporting purposes. Payments on the note during 2003 and 2002 totaled $12 million and $17 million, respectively, representing $9 million and $3 million in principal and interest, respectively, in 2003 and $13 million and $4 million in principal and interest, respectively, in 2002.

Progress Fuels sells coal feedstock to PVI to be used in its two synthetic fuel operations and is also the sales agent and operator of the facilities. The amount of revenue for sales and services during 2003 and 2002 was $181 million and $197 million, respectively. Amounts due from PVI at December 31, 2003 and 2002 were $19 million and $12 million, respectively. During 2003, in order to more effectively utilize cash resources, PFC and the two PVI synthetic fuel operations began to participate in a money pool with cash management functions provided by PFC. At December 31, 2003, Progress Fuels has a payable of $34 million to PVI.

The Company and each of its wholly-owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 13). In August 2002, PEC transferred reservation payments for the manufacture of two combustion turbines to PEF at PEC's original cost of $20 million. In December 2002, PVI transferred reservation payments for the manufacture of one combustion turbine and exhaust stack to PEF at PVI's original cost of $16 million. At December 31, 2002, PEF had a $14 million payable to PVI related to these transfers.

17. Financial Information by Business Segment

The Company's principal business segment is PEF, a utility engaged in the generation, purchase, transmission, distribution and sale of electricity primarily in Florida. The other reportable business segments are Progress Fuels' Energy & Related Services and Rail Services. The Energy & Related Services segment includes coal and synthetic fuel operations, natural gas production and sales, river terminal services and off-shore marine transportation. Rail Services' operations include railcar repair, rail parts reconditioning and sales, railcar leasing and sales, providing rail and track material, and scrap metal recycling. The Other category consists primarily of PTC, the Company's telecommunications subsidiary and the holding company, Florida Progress Corporation. PTC markets wholesale fiber-optic based capacity service in the Eastern United States and also markets wireless structure attachments to wireless communication companies and governmental entities. The Company allocates a portion of its operating expenses to business segments.

The Company's significant operations are geographically located in the United States with limited operations in Mexico and Canada. The Company's segments are based on differences in products and services, and therefore no additional disclosures are presented. Intersegment sales and transfers consist primarily of coal sales from the Energy and Related Services segment of Progress Fuels to PEF. The price Progress Fuels charges PEF is based on market rates for coal procurement and for water-borne transportation under a methodology approved by the FPSC. Rail transportation is also based on market rates plus a return allowed by the FPSC on equity in transportation equipment utilized in transporting coal to PEF. The allowed rate of return is currently 12%. No single customer accounted for 10% or more of unaffiliated revenues.

Segment net income (loss) for 2003 includes a long-lived asset impairment on certain assets at Kentucky May Mining Company of $15 million ($10 million after-tax) included in the Energy and Related Services segment. Segment net income (loss) for 2002 includes an estimated impairment on the assets held for sale of Railcar Ltd. of $67 million pre-tax ($45 million after-tax) included in the Rail Services segment and an asset impairment and other charges related to PTC totaling $233 million on a pre-tax basis ($144 million after-tax) included in the Other segment. The Company's business segment information for 2003 and 2002 is summarized below.

(in millions)	Utility	Energy and Related Services	Rail Services	Other	Consolidated
Year Ended December 31, 2003					
Unaffiliated revenues	$ 3,152	$ 982	$ 846	$ 28	$ 5,008
Intersegment revenues	-	346	1	(347)	-
Total revenues	3,152	1,328	847	(319)	5,008
Depreciation and amortization	307	66	20	6	399
Total interest charges, net	91	22	29	21	163
Impairment of long-lived assets and investments	-	15	-	-	15
Income tax expense (benefit)	147	(246)	2	(13)	(110)
Income (loss) from continuing operations	295	166	(1)	(17)	443
Total segment assets	7,306	1,009	586	335	9,236
Capital and investment expenditures	548	310	103	11	972
Year Ended December 31, 2002					
Unaffiliated revenues	$ 3,062	$ 690	$ 714	$ 34	$ 4,500
Intersegment revenues	-	329	5	(334)	-
Total revenues	3,062	1,019	719	(300)	4,500
Depreciation and amortization	295	34	20	12	361
Total interest charges, net	106	22	33	22	183
Impairment of long-lived assets and investments	-	-	67	214	281
Income tax expense (benefit)	163	(207)	(19)	(110)	(173)
Income (loss) from continuing operations	323	122	(47)	(168)	230
Total segment assets	6,678	794	529	137	8,138
Capital and investment expenditures	550	121	8	42	721

18. Other Income and Other Expense

Other income and expense includes interest income and other income and expense items as discussed below. The components of other, net as shown on the Statements of Income and Comprehensive Income for fiscal years 2003 and 2002 are as follows:

(in millions)	**2003**	2002
Other income		
Net financial trading gain (loss)	**$ (1)**	$ -
Nonregulated energy and delivery services income	**14**	17
AFUDC equity	**12**	2
Other	**2**	4
Total other income – Progress Energy Florida	**$ 27**	$ 23
Other income – Florida Progress	**5**	6
Total other income – Florida Progress	**$ 32**	$ 29
Other expense		
Nonregulated energy and delivery services expenses	**$ 11**	$ 15
Donations	**9**	10
Other	**-**	5
Total other expense – Progress Energy Florida	**$ 20**	$ 30
Loss from equity investments	**15**	5
Other expense – Florida Progress	**9**	14
Total other expense – Florida Progress	**$ 44**	$ 49
Other, net	**$ (12)**	$ (20)

Net financial trading gain (loss) represents non-asset-backed trades of electricity. Nonregulated energy and delivery services include power protection services and mass market programs (surge protection, appliance services and area light sales) and delivery, transmission and substation work for other utilities.

19. Commitments and Contingencies

A. Purchase Obligations

The following table reflects FPC's contractual cash obligations and other commercial commitments in the respective periods in which they are due.

(in millions)

Contractual Cash Obligations	2004	2005	2006	2007	2008	Thereafter
Fuel	$ 796	$ 368	$ 248	$ 159	$ 102	$ 790
Purchased power	317	329	340	349	357	4,237
Construction obligations	99	49	-	-	-	-
Other purchase obligations	16	5	18	11	16	107
Total	$ 1,228	$ 751	$ 606	$ 519	$ 475	$ 5,134

Fuel and Purchased Power

FPC has entered into various long-term contracts for oil, gas and coal. Payments under these commitments were $703 million and $830 million in 2003 and 2002, respectively. Estimated annual payments for firm commitments of fuel purchases and transportation costs under these contracts are approximately $796 million, $368 million, $248 million, $159 million and $102 million for 2004 through 2008, respectively, with approximately $790 payable thereafter.

Progress Fuels has two coal supply contracts with PEF through 2004, which require PEF to buy and Progress Fuels to supply substantially all of the coal and transportation requirements of four of PEF's generating units. In connection with these contracts, Progress Fuels has entered into several contracts with outside parties for the purchase of coal. The annual obligations for coal purchases and transportation under these contracts are $172 million, $52 million and $42 million for 2004, 2005 and 2006, respectively, with no obligations thereafter. The total cost incurred for these commitments in 2003 and 2002 was $284 million and $289 million, respectively.

PEF has long-term contracts for approximately 474 MW of purchased power with other utilities, including a contract with the Southern Company for approximately 414 MW of purchased power annually through 2010. PEF can lower these purchases to approximately 200 MW annually with a three-year notice. Total purchases, for both energy and capacity, under these agreements amounted to $141 million and $159 million for 2003 and 2002, respectively. Total capacity payments were $57 million and $51 million for 2003 and 2002, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million annually through 2009 and $30 million annually for 2010.

PEF has ongoing purchased power contracts with certain cogenerators (qualifying facilities) for 871 MW of capacity with expiration dates ranging from 2004 to 2025. These purchased power contracts provide for capacity and energy payments. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the qualifying facilities meeting certain contract performance obligations. In most cases, these contracts account for 100% of the generating capacity of each of the facilities. Of the 871 MW under contract, 831 MW currently are available to PEF. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $241 million and $232 million for 2003 and 2002, respectively. Minimum expected future capacity payments under these contracts at December 31, 2003 are $257 million, $269 million, $280 million, $289 million and $297 million for 2004 through 2008, respectively.

The FPSC allows the capacity payments to be recovered through a capacity cost recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost recovery clause.

Construction Obligations

PEF has purchase obligations related to various plant capital projects at the Hines Complex. Total payments under these contracts were $159 million and $110 million for 2003 and 2002 respectively. Future obligations under these contracts are $99 million and $49 million for 2004 and 2005, respectively.

Other

PEF has long-term service agreements for the Hines Complex. Total payments under these contracts were $3 million and $1 million for 2003 and 2002, respectively. Future obligations under these contracts are $16 million, $5 million, $18 million, $11 million and $16 million for 2004 through 2008, respectively, with approximately $107 million payable thereafter.

B. Other Commitments

Florida Progress has certain future commitments related to synthetic fuel facilities purchased that provide for contingent payments (royalties) of up to $25 million on synthetic fuel sales from Florida Progress' interests in these plants annually through 2007. The related agreements were amended in December 2001 to require the payment of minimum annual royalties of which Florida Progress' share is approximately $15 million through 2007. As a result of the amendment, Florida Progress recorded a liability (included in other liabilities and deferred credits on the Consolidated Balance Sheets) and a deferred asset (included in other assets and deferred debits in the Consolidated Balance Sheets) of approximately $52 million and $63 million at December 31, 2003 and 2002, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2003 and 2002, respectively, the portions of the asset and liability recorded that were classified as current were approximately $13 million and $13 million, respectively. The deferred asset will be amortized to expense each year as synthetic fuel sales are made. The maximum amounts payable under these agreements remain unchanged. Actual amounts paid under these agreements were approximately $1 million in

2003, $24 million in 2002. Future expected royalty payments are approximately $15 million for 2004 through 2007 and $4 million for 2008. The large decline in amount paid from 2002 to 2003 is due to the Company's right in the related agreements and their amendments that allows the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2003 royalty payments of approximately $25 million pending the establishment of the necessary escrow accounts. Once established, these funds will be placed into escrow.

C. Leases

The Company leases transportation equipment, office buildings, computer equipment, and other property and equipment with various terms and expiration dates. The Company generally requires the subsidiaries to pay all executory costs such as maintenance and insurance. Some rental payments include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Rent expense under operating leases totaled $42 million and $33 million during 2003 and 2002, respectively. In addition, PTC has entered into capital leases for equipment. Assets recorded under capital leases totaled $4 million and $3 million at December 31, 2003 and 2002, respectively. Accumulated amortization was not significant. These assets were written down in conjunction with the impairments of PTC recorded during the third quarter of 2002 (See Note 9).

Minimum annual rental payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2003 are:

(in millions)	Capital Leases	Operating Leases
2004	$ 1	$ 20
2005	1	18
2006	1	16
2007	1	12
2008	1	9
Thereafter	9	54
	$ 14	$ 129
Less amount representing imputed interest	(4)	
Present value of net minimum lease payments under capital lease	$ 10	

The Company is also a lessor of land, buildings, railcars and other types of properties it owns under operating leases with various terms and expiration dates. The leased buildings and railcars are depreciated under the same terms as other buildings and railcars included in diversified business property. Minimum rentals receivable under noncancelable leases for 2004 through 2008, in millions is $4, $4, $3, $1, and $1, respectively and $18 million thereafter. These rental receivable totals exclude all leases attributable to Railcar Ltd. which was sold during the first quarter of 2004 (See Note 3B).

PEF is the lessor of electric poles, streetlights and other facilities. Rents received are contingent upon usage and totaled $56 million and $53 million for 2003 and 2002, respectively.

D. Guarantees

As a part of normal business, Florida Progress and certain subsidiaries including PEF enter into various agreements providing financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2003, management does not believe conditions are likely for performance under these agreements.

Guarantees at December 31, 2003, are summarized in the table below and discussed more fully in the subsequent paragraphs:

(in millions)	
Guarantees issued on behalf of the Company and affiliates	
Standby letters of credit	$ 33
Surety bonds	-
Other guarantees	21
Guarantees issued on behalf of third parties	
Securities of affiliated trust	300
Other guarantees	13
Total	$367

Standby Letters of Credit
The Company has issued standby letters of credit to financial institutions for the benefit of third parties that have extended credit to the Company and certain subsidiaries. Of the total standby letters of credit issued, PEF has issued commitments totaling $2 million. These letters of credit have been issued primarily for the purpose of supporting payments of trade payables, securing performance under contracts and lease obligations and self insurance for workers compensation. If a subsidiary does not pay amounts when due under a covered contract, the counterparty may present its claim for payment to the financial institution, which will in turn request payment from the Company. Any amounts owed by the Company's subsidiaries are reflected in the Company's Consolidated Balance Sheets.

Surety Bonds
At December 31, 2003, the Company had $0.2 million in surety bonds, of which PEF accounted for the entire amount, purchased primarily for purposes such as providing workers compensation coverage and obtaining licenses, permits and rights-of-way. To the extent liabilities are incurred as a result of the activities covered by the surety bonds, such liabilities are included in the Balance Sheets.

Other Guarantees
The Company has total other guarantees outstanding of approximately $34 million. Included in the $34 million are $3 million of guarantees issued on behalf of third parties related to obligations on leasing arrangements and $10 million in support of synthetic fuel operations at a third party plant. The Company estimates it will have to perform under the third party guarantees related to the leasing agreements and as such $3 million has been accrued and is reflected in the Company's Consolidated Balance Sheets. The remaining $21 million in other guarantees is related primarily to prompt performance payments and other payments subject to contingencies.

Securities of Affiliated Trust
The Company has guaranteed certain payments of an affiliated company, FPC Capital I (the Trust). Due to the nature of the relationship between the Trust and Florida Progress Funding Corporation, the Company has guaranteed the payment of all distributions related to the Trust's outstanding mandatorily redeemable preferred securities. At December 31, 2003, the Trust had outstanding 12 million shares of the securities with a liquidation value of $300 million. See discussion at Note 11F for further discussion of the guarantee.

Guarantees Issued by Progress Energy
Progress Energy has issued approximately $27 million of guarantees on behalf of Progress Fuels and its subsidiaries for obligations under coal trading operations.

E. Claims and Uncertainties

The Company is subject to federal, state and local regulations addressing hazardous and solid waste management, air and water quality and other environmental matters.

Hazardous and Solid Waste Management

Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. The principal regulatory agency that is responsible for a specific former manufactured gas plant (MGP) site depends largely upon the state in which the site is located. There are several MGP sites to which the Company has some connection. In this regard, PEF and other potentially responsible parties, are participating in, investigating and, if necessary, remediating former MGP sites with several regulatory agencies, including, but not limited to, the U.S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP). In addition, PEF is periodically notified by regulators such as the EPA and various state agencies of its involvement or potential involvement in sites, other than MGP sites, that may require investigation and/or remediation.

PEF At December 31, 2003, PEF has accrued $18 million for probable and estimable costs related to various environmental sites. Of this accrual, $12 million is for costs associated with the remediation of distribution transformers which are more fully discussed below. The remaining $6 million is related to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation costs. PEF does not believe that it can provide an estimate of the reasonably possible total remediation costs beyond what is currently accrued.

In 2002, PEF accrued approximately $3 million for investigation and remediation costs associated with distribution transformers and received approval from the FPSC for annual recovery of these environmental costs through the Environmental Cost Recovery Clause (ECRC). In September 2003, PEF accrued an additional $15 million for similar environmental costs as a result of increased sites and estimated costs per site. PEF has received approval from the FPSC to recover these costs through the ECRC. As more activity occurs at these sites, PEF will assess the need to adjust the accruals.

These accruals have been recorded on an undiscounted basis. PEF measures its liability for these sites based on available evidence including its experience in investigating and remediating environmentally impaired sites. This process often includes assessing and developing cost-sharing arrangements with other potentially responsible parties. Presently, PEF cannot determine the total costs that may be incurred in connection with the remediation of all sites.

Florida Progress In 2001, Progress Fuels sold its Inland Marine Transportation business to AEP Resources, Inc. Progress Fuels established an accrual to address indemnities and retained environmental liability associated with the transaction. Progress Fuels estimates that its contractual liability to AEP Resources, Inc. associated with Inland Marine Transportation is $4 million at December 31, 2003 and has accrued such amount. The previous accrual of $10 million was reduced in 2003 based on a change in estimate. This accrual has been determined on an undiscounted basis. Progress Fuels measures its liability for this site based on estimable and probable remediation scenarios. The Company believes that it is not reasonably probable that additional costs will be incurred related to the environmental indemnification provision beyond the amount accrued. The Company cannot predict the outcome of this matter.

PEF has filed claims with the Company's general liability insurance carriers to recover costs arising out of actual or potential environmental liabilities. Some claims have been settled and others are still pending. The Company cannot predict the outcome of this matter.

Certain historical sites exist that are being addressed voluntarily by Progress Fuels and FPC. The Company cannot determine the total costs that may be incurred in connection with these sites. The Company cannot predict the outcome of this matter.

Rail Services is voluntarily addressing certain historical waste sites. The Company cannot determine the total costs that may be incurred in connection with these sites. The Company cannot predict the outcome of this matter.

The Company is also currently in the process of assessing potential costs and exposures at other environmentally impaired sites. As the assessments are developed and analyzed, the Company will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated.

Air Quality

There has been and may be further proposed federal legislation requiring reductions in air emissions for nitrogen oxides, sulfur dioxide, carbon dioxide and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multi-pollutant approach to air pollution control could involve significant capital costs which could be material to the Company's consolidated financial position or results of operations. Some companies may seek recovery of the related cost through rate adjustments or similar mechanisms. However, the Company cannot predict the outcome of this matter.

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether modifications at those facilities were subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. PEF was asked to provide information to the EPA as part of this initiative and cooperated in providing the requested information. During 2003, PEF received a supplemental information request from the EPA and responded to it. The EPA initiated civil enforcement actions against other unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements calling for expenditures ranging from $1.0 billion to $1.4 billion. A utility that was not subject to a civil enforcement action settled its New Source Review issues with the EPA for $300 million. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related cost through rate adjustments or similar mechanisms. The Company cannot predict the outcome of the EPA's initiative or its impact, if any, on the Company.

In 2003, the EPA published a final rule addressing routine equipment replacement under the New Source Review program. The rule defines routine equipment replacement and the types of activities that are not subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The rule was challenged in the Federal Appeals Court and its implementation stayed. The Company cannot predict the outcome of this matter.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress conveyed that mercury is not a risk to the average American and expressed uncertainty about whether reductions in mercury emissions from coal-fired power plants would reduce human exposure. Nevertheless, the EPA determined in 2000 that regulation of mercury emissions from coal-fired power plants was appropriate. In 2003, the EPA proposed, and solicited comment on, two alternative control plans that would limit mercury emissions from coal-fired power plants. The agency has indicated that it will choose one of the alternatives as the final rule, which is expected to be promulgated in December 2004. Achieving compliance with either proposal could involve significant capital costs which could be material to the Company's financial condition or results of operations. However, the Company cannot predict the outcome of this matter.

In conjunction with the proposed mercury rule, the EPA proposed a Maximum Available Control Technology (MACT) standard to regulate nickel emissions from residual oil-fired units. The agency estimates the proposal will reduce national nickel emissions to approximately 103 tons. The rule is expected to become final in December 2004. The Company cannot predict the outcome of this matter.

In December 2003, the EPA released its proposed Interstate Air Quality Rule (commonly known as the Fine Particulate Transport Rule and/or the Regional Transport Rule). The EPA's proposal requires 28 jurisdictions, including North Carolina, South Carolina, Georgia and Florida, to further reduce nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions in order to attain pre-set NOx and SO2 emissions levels (which have not yet been determined). The rule is expected to become final in 2004. The installation of controls necessary to comply with the rule could involve significant capital costs.

In 2004, a bill was introduced in the Florida legislature that would require significant reductions in SO2, NOx and particulate emissions from certain coal, natural gas and oil-fired generating units owned or operated by investor-owned electric utilities, including PEF. The SO2 and NOx reductions would be effective beginning with calendar year 2010 and the particulate reductions would be effective beginning with calendar year 2012. Under the proposed legislation, the FPSC would be authorized to allow the utilities to recover the costs of compliance with the emission reductions over a period not greater than seven years beginning in 2005, but the utilities' rates would be frozen at 2004 levels for at least five years of the maximum recovery period. The Company cannot predict the outcome of this matter.

Water Quality

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated. Integration of these new wastewater streams into existing wastewater treatment processes may result in permitting, construction and water treatment challenges to the Company in the immediate and extended future.

After many years of litigation and settlement negotiations, the EPA is scheduled to publish final regulations in February 2004 for the implementation of Section 316(b) of the Clean Water Act. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems located at existing facilities. Over the next several years, these regulations may require the facilities to mitigate the effects to aquatic organisms by undertaking intake modifications or other restorative activities. Substantial costs could be incurred by the facilities in order to comply with the new regulations. The Company cannot predict the outcome and impacts to the facilities at this time.

The EPA has published for comment a draft Environmental Impact Statement (EIS) for surface coal mining (sometimes referred to as "mountaintop mining") and valley fills in the Appalachian coal region, where Progress Fuels currently operates a surface mine and may operate others in the future. The final EIS, when published, may affect regulations for the permitting of mines and the cost of compliance with environmental regulations. Regulatory changes for mining may also affect the cost of fuel for the PEC and PEF fueled electric generating plants. The Company cannot predict the outcome of this matter.

Other Environmental Matters

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of carbon dioxide and other greenhouse gases. The United States has not adopted the Kyoto Protocol; however, a number of carbon dioxide emissions control proposals have been advanced in Congress and by the Bush Administration. The Bush Administration favors voluntary programs. Reductions in carbon dioxide emissions to the levels specified by the Kyoto Protocol and some legislative proposals could be materially adverse to the Company's financials and operations if associated costs cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration, and is evaluating options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company cannot predict the outcome of this matter.

Other Contingencies

1) <u>Franchise Litigation</u>

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. As discussed below, three other cities, with a total of approximately 30,000 customers, have subsequently settled their lawsuits with PEF and signed new, 30-year franchise agreements. The lawsuits principally seek (1) a declaratory judgment that the cities have the right to purchase PEF's electric distribution system located within the municipal boundaries of the cities, (2) a declaratory judgment that the value of the distribution system must be determined through arbitration, and (3) injunctive relief requiring PEF to continue to collect from PEF's customers and remit to the cities, franchise fees during the pending litigation, and as long as PEF continues to occupy the cities' rights-of-way to provide electric service, notwithstanding the expiration of the franchise ordinances under which PEF had agreed to collect such fees. Five circuit courts have entered orders requiring arbitration to establish the purchase price of PEF's electric distribution system within five cities. Two appellate courts have upheld those circuit court decisions and authorized cities to determine the value of PEF's electric distribution system within the cities through arbitration. Arbitration in one of the cases (the City of Casselberry) was held in August 2002. Following arbitration, the parties entered settlement discussions, and in July 2003 the City approved a settlement agreement and a new, 30-year franchise agreement with PEF. The settlement resolves all pending litigation with that City. A second arbitration (with the 13,000-customer City of Winter Park) was completed in February 2003. That arbitration panel issued an award in May 2003 setting the value of PEF's distribution system within the City of Winter Park at approximately $32 million, not including separation and reintegration and construction work in progress, which could add several million dollars to the award. The panel also awarded PEF approximately $11 million in stranded costs. In September 2003, Winter Park voters passed a referendum that would authorize the City to issue bonds of up to approximately $50 million to acquire PEF's electric distribution system. The City has not yet definitively decided whether it will acquire the system, but has indicated that it will seek wholesale power supply bids and bids to operate and maintain the distribution system. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined. A third arbitration (with the 2,500-customer Town of Belleair) was completed in June 2003. In September 2003, the arbitration panel issued an award in that case setting the value of the electric distribution system within the Town at approximately $6 million. The panel further required the Town to pay to PEF its requested $1 million in separation and reintegration costs and $2 million in stranded costs. The Town has not yet decided whether it will attempt to acquire the system. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined. A fourth arbitration (with the 13,000-customer City of Apopka) had been scheduled for January 2004. In December 2003, the Apopka City

Commission voted on first reading to approve a settlement agreement and a 30-year franchise with PEF. The settlement and franchise became effective upon approval by the Commission at a second reading of the franchise in January 2004. The settlement resolves all outstanding litigation between the parties. Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled.

As part of the above litigation, two appellate courts have also reached opposite conclusions regarding whether PEF must continue to collect from its customers and remit to the cities "franchise fees" under the expired franchise ordinances. PEF has filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. The Florida Supreme Court held oral argument in one of the appeals in August 2003. Subsequently, the Court requested briefing from the parties in the other appeal, which was completed in November 2003. The Court has not yet issued a decision in these cases. PEF cannot predict the outcome of these matters at this time.

2) DOE Litigation

As required under the Nuclear Waste Policy Act of 1982, PEF entered into a contract with the U.S. Department of Energy (DOE) under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

In April 1995, the DOE issued a final interpretation that it did not have an unconditional obligation to take spent nuclear fuel by January 31, 1998. In Indiana & Michigan Power v. DOE, the Court of Appeals vacated the DOE's final interpretation and ruled that the DOE had an unconditional obligation to begin taking spent nuclear fuel. The Court did not specify a remedy because the DOE was not yet in default.

After the DOE failed to comply with the decision in Indiana & Michigan Power v. DOE, a group of utilities petitioned the Court of Appeals in Northern States Power (NSP) v. DOE, seeking an order requiring the DOE to begin taking spent nuclear fuel by January 31, 1998. The DOE took the position that its delay was unavoidable, and the DOE was excused from performance under the terms and conditions of the contract. The Court of Appeals did not order the DOE to begin taking spent nuclear fuel, stating that the utilities had a potentially adequate remedy by filing a claim for damages under the contract.

After the DOE failed to begin taking spent nuclear fuel by January 31, 1998, a group of utilities filed a motion with the Court of Appeals to enforce the mandate in NSP v. DOE. Specifically, this group of utilities asked the Court to permit the utilities to escrow their waste fee payments, to order the DOE not to use the waste fund to pay damages to the utilities, and to order the DOE to establish a schedule for disposal of spent nuclear fuel. The Court denied this motion based primarily on the grounds that a review of the matter was premature, and that some of the requested remedies fell outside of the mandate in NSP v. DOE.

Subsequently, a number of utilities each filed an action for damages in the Federal Court of Claims. The U.S. Circuit Court of Appeals (Federal Circuit) has ruled that utilities may sue the DOE for damages in the Federal Court of Claims instead of having to file an administrative claim with DOE.

On January 14, 2004, PEF filed a complaint with the United States Court of Federal Claims against the United States of America (Department of Energy) claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from various Progress Energy facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Similar suits have been initiated by over two dozen other utilities.

In July 2002, Congress passed an override resolution to Nevada's veto of DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nevada. DOE plans to submit a license application for the Yucca Mountain facility by the end of 2004. On November 5, 2003, Congressional negotiators approved $580 million for fiscal year 2004 for the Yucca Mountain project, $123 million more than the previous year. PEF cannot predict the outcome of this matter.

PEF is currently storing spent nuclear fuel onsite in spent fuel pools. If PEF does not seek renewal of the Crystal River Nuclear Plant (CR3) operating license, CR3 will have sufficient storage capacity in place for fuel consumed through the end of the expiration of the license in 2016. If PEF extends the CR3 operating license, dry storage may be necessary.

3) Easement Litigation

In December 1998, PEF was served with a class action lawsuit seeking damages, declaratory and injunctive relief for the alleged improper use of electric transmission easements. The plaintiffs contended that the licensing of fiber-optic telecommunications lines to third parties or telecommunications companies for other than PEF's internal use along the electric transmission line right-of-way exceeds the authority granted in the easements. In 1999, plaintiffs amended their complaint to add PTC. After several legal motions and appeals over the years the Company and the appellants reached a settlement resolving the appellants' dispute in 2003. In May 2003 the trial court entered an Amended Final Judgment approving the mandatory class settlement. No appeals have been taken from that judgment, and the time to appeal has expired. In July 2003, PEF, the class representatives and the appellants filed a joint withdrawal of all pending motions with the First District Court of Appeal. The First District Court of Appeal acknowledged the withdrawal of all pending motions and issued a mandate in July 2003. Under the terms of the mandatory class settlement, PEF made settlement payments to class members in August 2003. The settlement payments did not have a material adverse effect upon PEF's financial condition or results of operations.

4) Advanced Separation Technologies (AST)

In 1996, Florida Progress sold its 80% interest in AST to Calgon Carbon Corporation (Calgon) for net proceeds of $56 million in cash. In January 1998, Calgon filed a lawsuit against Florida Progress and the other selling shareholder and amended it in April 1998, alleging misstatement of AST's 1996 revenues, assets and liabilities, seeking damages and granting Calgon the right to rescind the sale. The lawsuit also accused the sellers of failing to disclose flaws in AST's manufacturing process and a lack of quality control. Florida Progress believes that the aggregate total of all legitimate warranty claims by customers of AST for which it is probable that Florida Progress will be responsible for under the Stock Purchase Agreement with Calgon is approximately $3 million, and accordingly, accrued $3 million in the third quarter of 1999 as an estimate of probable loss. All parties filed motions for summary judgment in July 2001. The summary judgment motions of Calgon and the other selling shareholder were denied in April of 2002. The summary judgment motion of Florida Progress was withdrawn pending a legal challenge to portions of the report of Calgon's expert, Arthur Andersen, which had been used to oppose summary judgment. In September 2003, the United States District Court for the Western District of Pennsylvania issued final orders excluding from evidence in the case that portion of Arthur Andersen's damage analysis based on the discounted cash flow methodology of valuation. The Court did not exclude Arthur Andersen's use of the guideline publicly traded company methodology in its damage analysis. Florida Progress filed a renewed motion for summary judgment in October 2003, which is pending. The Company cannot predict the outcome of this matter, but will present a vigorous defense.

5) Other Legal Matters

Florida Progress and PEF are involved in various other claims and legal actions arising in the ordinary course of business, some of which involve claims for substantial amounts. Where appropriate, accruals have been made in accordance with SFAS No. 5, "Accounting for Contingencies," to provide for such matters. Florida Progress and PEF believe the ultimate disposition of these matters will not have a material adverse effect upon either Company's consolidated financial position, results of operation or liquidity.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceeding Year				
2	Preceding yr. Reclassification from Account 219 Net Income				
3	Preceding Year Changes in Fair Value		(2,365,547)		
4	Total (lines 2 and 3)		(2,365,547)		
5	Balance of Account 219 at End of Preceding Yr/Beginning of Current Yr		(2,365,547)		
6	Current Year Reclassification From Account 219 to Net Income				
7	Current Year Changes in Fair Value		(1,339,368)		
8	Total (lines 6 and 7)		(1,339,368)		
9	Balance of Account 219 at End of Current Year		(3,704,915)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges [Interest Rate Lock] (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 72) (i)	Total Comprehensive Income (j)
1					
2					
3	(318,366)		(2,683,913)		
4	(318,366)		(2,683,913)	324,105,703	321,421,790
5	(318,366)		(2,683,913)		
6	239,750		239,750		
7			(1,339,368)		
8	239,750		(1,099,618)	296,354,489	295,254,871
9	(78,616)		(3,783,531)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,249,183,604	7,246,652,364
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	906,804,234	906,804,234
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,155,987,838	8,153,456,598
9	Leased to Others		
10	Held for Future Use	7,921,254	7,921,254
11	Construction Work in Progress	328,267,599	328,267,599
12	Acquisition Adjustments	-6,307,202	-6,307,202
13	Total Utility Plant (8 thru 12)	8,485,869,489	8,483,338,249
14	Accum Prov for Depr, Amort, & Depl	4,020,429,793	4,020,020,272
15	Net Utility Plant (13 less 14)	4,465,439,696	4,463,317,977
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,940,367,967	3,940,367,967
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	81,510,924	81,101,403
22	Total In Service (18 thru 21)	4,021,878,891	4,021,469,370
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	-1,449,098	-1,449,098
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,020,429,793	4,020,020,272

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
	2,531,240				3
					4
					5
					6
					7
	2,531,240				8
					9
					10
					11
					12
	2,531,240				13
	409,521				14
	2,121,719				15
					16
					17
					18
					19
					20
	409,521				21
	409,521				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	409,521				33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	102,671,109	366,691
10	SUBTOTAL (Total 8 & 9)	102,671,109	
11	Spent Nuclear Fuel (120.4)	403,719,480	50,533,630
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	466,130,870	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	40,259,719	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
			2
			3
			4
			5
			6
			7
			8
		103,037,800	9
		103,037,800	10
	342,735,672	111,517,438	11
			12
-22,051,793	342,735,672	145,446,991	13
		69,108,247	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 11 Column: e

$342,735,672 Transferred to 120.5 Accum Prov for Amortization of Nuclear Fuel Assemblies.

Schedule Page: 202 Line No.: 13 Column: e

$ 342,735,672 Transferred from 120.4 Spent Nuclear Fuel.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	101,509,390	14,887,851
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	101,509,390	14,887,851
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,450,314	
9	(311) Structures and Improvements	279,798,101	3,591,511
10	(312) Boiler Plant Equipment	796,152,439	27,148,753
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	427,252,248	21,390,726
13	(315) Accessory Electric Equipment	161,713,098	1,688,979
14	(316) Misc. Power Plant Equipment	27,624,970	1,227,003
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,698,991,170	55,046,972
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	41,218	
19	(321) Structures and Improvements	215,130,062	29,273,065
20	(322) Reactor Plant Equipment	261,081,670	4,735,228
21	(323) Turbogenerator Units	87,597,731	2,017,845
22	(324) Accessory Electric Equipment	180,144,838	2,193,397
23	(325) Misc. Power Plant Equipment	35,946,342	4,690,177
24	(326) Asset Retirement Costs for Nuclear Production		77,064,813
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	779,941,861	119,974,525
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,546,153	2,099,914
38	(341) Structures and Improvements	63,500,818	13,379,004
39	(342) Fuel Holders, Products, and Accessories	51,009,832	715,122
40	(343) Prime Movers	601,391,569	87,219,721
41	(344) Generators	129,621,318	98,138,599
42	(345) Accessory Electric Equipment	81,400,118	43,329,324
43	(346) Misc. Power Plant Equipment	7,816,844	4,147,004

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			116,397,241		4
			116,397,241		5
					6
					7
			6,450,314		8
252,623			283,136,989		9
9,886,226			813,414,966		10
					11
10,415,939			438,227,035		12
454,609			162,947,468		13
214,570			28,637,403		14
					15
21,223,967			1,732,814,175		16
					17
			41,218		18
16,661			244,386,466		19
757,633			265,059,265		20
257,339			89,358,237		21
12,189			182,326,046		22
			40,636,519		23
			77,064,813		24
1,043,822			898,872,564		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			18,646,067		37
133,456			76,746,366		38
1,136,615			50,588,339		39
9,005,531			679,605,759		40
2,267,715			225,492,202		41
311,731			124,417,711		42
9,234			11,954,614		43

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	951,286,652	249,028,688
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,430,219,683	424,050,185
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	49,285,470	2,788,859
49	(352) Structures and Improvements	17,425,034	800,022
50	(353) Station Equipment	398,847,480	14,043,304
51	(354) Towers and Fixtures	69,029,576	
52	(355) Poles and Fixtures	228,557,839	14,783,794
53	(356) Overhead Conductors and Devices	195,003,971	5,485,295
54	(357) Underground Conduit	6,856,135	-3,043
55	(358) Underground Conductors and Devices	9,494,815	-543
56	(359) Roads and Trails	1,923,175	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	976,423,495	37,897,688
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	19,556,281	2,406,654
61	(361) Structures and Improvements	18,708,703	626,240
62	(362) Station Equipment	333,811,093	10,367,807
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	372,013,280	30,439,012
65	(365) Overhead Conductors and Devices	404,075,721	32,786,737
66	(366) Underground Conduit	132,868,893	11,975,148
67	(367) Underground Conductors and Devices	380,407,468	24,883,373
68	(368) Line Transformers	374,705,729	18,874,269
69	(369) Services	355,627,356	35,192,077
70	(370) Meters	118,346,975	5,433,566
71	(371) Installations on Customer Premises	2,098,612	828,595
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	216,018,806	12,718,119
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,728,238,917	186,531,597
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	7,700,570	3,844,037
78	(390) Structures and Improvements	67,168,211	13,269,407
79	(391) Office Furniture and Equipment	31,302,891	3,497,621
80	(392) Transportation Equipment	83,229,005	45,996,627
81	(393) Stores Equipment	2,328,763	792,201
82	(394) Tools, Shop and Garage Equipment	7,951,267	1,612,035
83	(395) Laboratory Equipment	3,833,562	245,354
84	(396) Power Operated Equipment	2,051,193	552,720
85	(397) Communication Equipment	35,009,419	26,385,492
86	(398) Miscellaneous Equipment	3,303,688	146,949
87	SUBTOTAL (Enter Total of lines 77 thru 86)	243,878,569	96,342,443
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	243,878,569	96,342,443
91	TOTAL (Accounts 101 and 106)	7,480,270,054	759,709,764
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	7,480,270,054	759,709,764

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					44
12,864,282			1,187,451,058		45
35,132,071			3,819,137,797		46
					47
			52,074,329		48
4,549			18,220,507		49
1,943,744	76,761		411,023,801		50
			69,029,576		51
735,174			242,606,459		52
286,972			200,202,294		53
			6,853,092		54
			9,494,272		55
			1,923,175		56
					57
2,970,439	76,761		1,011,427,505		58
					59
			21,962,935		60
			19,334,943		61
2,253,423	86,208		342,011,685		62
					63
576,246			401,876,046		64
3,517,302			433,345,156		65
138,797			144,705,244		66
1,791,152			403,499,689		67
4,743,814			388,836,184		68
8,950,967			381,868,466		69
1,406,483			122,374,058		70
			2,927,207		71
					72
1,510,434			227,226,491		73
					74
24,888,618	86,208		2,889,968,104		75
					76
2,494,886	1,151,637		10,201,358		77
6,174,853			74,262,765		78
			34,800,512		79
16,397,076			112,828,556		80
			3,120,964		81
146,346			9,416,956		82
			4,078,916		83
			2,603,913		84
119,073		527,611	61,803,449		85
42,075			3,408,562		86
25,374,309	1,151,637	527,611	316,525,951		87
					88
					89
25,374,309	1,151,637	527,611	316,525,951		90
88,365,437	1,314,606	527,611	8,153,456,598		91
					92
					93
					94
88,365,437	1,314,606	527,611	8,153,456,598		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	PERRY - CROSS CITY - DUNNELLON	10/87	05/05	1,046,410
3	PERRY - FLORIDA STATE LINE	12/92	05/05	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	05/05	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	11/03	267,012
6				
7				
8	OTHER LAND AND RIGHTS			1,461,721
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - CROSS CITY - DUNNELLON	07/90	05/05	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			7,921,254

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Hines #3 CC Master	79,192,195
2	Florida 04 Peaking	37,532,315
3	Energy Delivery - Replace Radio System	15,218,819
4	Bentley Settlement	11,765,865
5	DOT & Gov't Work	11,437,241
6	CTE - Mid-Point Recloser	10,313,920
7	CP IC P11 Major Inspection	5,676,152
8	NRC Dire SEC Comp. Meas.	4,234,194
9	FPC EMS Upgrade Conversion	4,113,824
10	Barcola Pebbledale Line build	3,418,368
11	Vandolah-Whidden	3,397,388
12	FSD 69KV Rebuild	3,306,365
13	CTE Fuse Coordination	3,227,553
14	Tavares-WTR (SECO)	3,071,610
15	Dist. OPS & Support	2,625,838
16	CW Amertap Design	2,618,859
17	CP DEB P1-6 2002 Controls Conv.	2,358,993
18	FMS Longwood OC-P3	2,295,040
19	CTE- Sectionalizers	2,223,358
20	CP TB 2004 Spring HGP & Refurb	2,031,139
21	CTE - Replace Poles	2,014,489
22	Dundee Transfer	2,014,387
23	Copper Dep	1,921,213
24	FMS Wildwood Impr	1,899,369
25	PQ&R	1,791,523
26	CTE - Padmnt XFMR Replacement	1,772,933
27	CP Bay 2002 Control Conversion	1,761,905
28	Inlet Fltr Hus DCTT	1,656,933
29	Winter Park	1,539,521
30	BCR - Repl PS & I	1,421,703
31	FL Remittance Proc. Equipment	1,376,654
32	Cond Cleaning System	1,326,221
33	Pressurizer Project	1,284,177
34	Power Uprate Project	1,212,597
35	Mobile Link	1,206,978
36	Champions Gate New	1,127,644
37	Turbine Blade Replacement	1,117,315
38	CP IC P7 Major Inspection	1,097,812
39	DEB P9 Major Inspection	1,072,017
40	Wireless Data Network	1,043,991
41	CTE - OHGW- 901T8 IJ 312-472	1,031,851
42	Other Minor Projects	87,517,330
43	TOTAL	328,267,599

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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,004,874,944	4,004,874,944		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	243,129,441	243,129,441		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,491,608	1,491,608		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,430,022	6,430,022		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil	544,759	544,759		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	251,595,830	251,595,830		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	86,432,981	86,432,981		
13	Cost of Removal	10,129,676	10,129,676		
14	Salvage (Credit)	11,981,297	11,981,297		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	84,581,360	84,581,360		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	See Footnote	-231,521,447	-231,521,447		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,940,367,967	3,940,367,967		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,230,621,103	1,230,621,103		
21	Nuclear Production	620,366,893	620,366,893		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	365,997,917	365,997,917		
25	Transmission	454,880,667	454,880,667		
26	Distribution	1,207,190,160	1,207,190,160		
27	General	61,311,227	61,311,227		
28	TOTAL (Enter Total of lines 20 thru 27)	3,940,367,967	3,940,367,967		

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FOOTNOTE DATA

Schedule Page: 219 Line No.: 3 Column: c

Depreciation Expense per Line 11, Column b Page 336	$243,276,489
Depreciation Expense per Line 3, Column b Page 219	$243,129,441

Acct 403 Expense booked to Reserve Acct. 1193000	$ 147,048
	============
Page 207 Line 91 Column D - Total Retirements - EPIS	$ 88,365,437
Page 219 Line 12 Column B - Total Retirements - Accum. Reserve	$ 86,432,981

Retirements to Account 111, Limited Term Electric Property	$ 1,932,456
	=============

Other Debit or Credit Items:

Nuclear Decommissioning Amounts moved from Acct. 108	($283,516,729)
Crystal River ARO Established	$ 38,470,557
2002 Transportation Accrual Reversal	($ 1,400,000)
Accumulated Reserve Transfer on Communication Equipment	$ 14,957,610
TECO Transmission Line Acquisition Accrual	$ 88,727
Solution Store Sale Adjustments	($ 121,612)

Total Other Dr/Cr Items - Line 17, Page 219	($231,521,447)
	==============

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	111,111,824	90,516,921	Power Supply
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	80,188,410	101,826,110	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	28,866,511	21,681,603	Power Supply
8	Transmission Plant (Estimated)	1,345,231	986,329	Transmission
9	Distribution Plant (Estimated)	7,143,133	5,149,093	Customer Service
10	Assigned to - Other (provide details in footnote)	676,397	552,633	Various
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	118,219,682	130,195,768	
12	Merchandise (Account 155)	237,806	424,410	
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	5,473,989	9,361,873	Various
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	235,043,301	230,498,972	

Schedule Page: 227 Line No.: 15 Column: b

Account 163- Stores Expense Undistributed was charged with $104,137.17 and credited with $76,777.36 for a net charge of $27,359.81 during 2002. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2002.

Schedule Page: 227 Line No.: 15 Column: c

Account 163- Stores Expense Undistributed was charged with $444,191 and credited with $41,475 for a net charge of $402,716 during 2003. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2003.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2004 No. (d)	2004 Amt. (e)
1	Balance-Beginning of Year	34,529.00	1,237,884	125,653.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	125,653.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	VARIOUS PURCHASES AND				
10	TRANSFERS (INCLUDING				
11	MORGAN STANLEY,				
12	RELIANT, AND KEYSPAN)	35,000.00	7,146,999		
13					
14					
15	Total	35,000.00	7,146,999		
16					
17	Relinquished During Year:				
18	Charges to Account 509	157,237.00	7,472,794		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	37,945.00	912,089	125,653.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,343.00		3,343.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year	3,343.00		3,343.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2005		2006		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
125,653.00		125,653.00		2,642,367.00		3,053,855.00	1,237,884	1
								2
								3
						125,653.00		4
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						35,000.00	7,146,999	12
								13
								14
						35,000.00	7,146,999	15
								16
								17
						157,237.00	7,472,794	18
								19
								20
								21
								22
								23
								24
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								28
125,653.00		125,653.00		2,642,367.00		3,057,271.00	912,089	29
								30
								31
								32
								33
								34
								35
3,343.00		3,343.00		73,411.00		86,783.00		36
								37
								38
								39
3,343.00		3,343.00		73,411.00		86,783.00		40
								41
								42
								43
					1,707,393		1,707,393	44
								45
								46

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	Accumulated Deferred Taxes - FAS109		410100	2,299,000	114,114,000
2	Period of Amortization - Amortization occurs				
3	as temporary differences occur.				
4					
5					
6	Nuclear Decom/Decontamination - Retail		5188200	1,876,898	4,782,597
7	Amortization Period = 12 months.				
8					
9	Nuclear Decom/Decontamination - Whsle	307,482	5188200	49,713	553,199
10	Amortization Period = 12 months				
11					
12	Regulatory Asset - Tiger Bay - Retail		407002	46,601,202	
13					
14	Load Control Switches - Investment	721,916	1861902	1,786,447	2,862,348
15	Load Control Switches - Amortization	1,786,448	9080120	642,514	-1,265,104
16					
17	Sebring Transition Rider	18,707	1861904	2,400,004	14,427,566
18	Sebring - Over (Under) Recovered	2,400,004	4044002	2,429,828	-1,539,917
19					
20	Interest on Tax Deficiency	20,442,504	4310024	19,317,833	
21					
22	Deferred Energy Conservation Expense	5,082,364	9080110	4,421,655	-7,464,313
23					
24	Deferred GPIF Asset	2,781,223	4560096	608,057	2,781,223
25					
26	Def Fuel Expense - Retail - 01/03 -12/03	181,326,148	5572002	7,876,431	173,449,717
27	Def Fuel Expense - Retail - 01/02 - 12/02	8,646,440	5572002	2,554,583	37,777,646
28	Def Cap Expense 01/02 - 12/02		5572001	4,408,138	
29	Def Fuel Expense - Full Req	8,650,094	5572002	905,060	2,482,402
30	Def Fuel Expense-Whlse-Partial Req.		5572002	6,671,834	
31	Deferred Environmental Cost Recovery	10,719,394	9350003	847,887	9,910,340
32	Accrued Environmental Cost Recovery	21,602,688	2284800	13,119,188	11,883,500
33					
34	RTO Set Up Costs	341,000			3,695,208
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	264,826,412		118,816,272	368,450,412

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Job Orders Work in Process	1,776,110	53,808,190	various	54,808,169	776,131
2						
3	Repair Transformer & Rotor	3,931,912	381,694	402	2,215,991	2,097,615
4						
5	No. Cent. Franchise Arbitration	269,020	59,432	402	128,022	200,430
6						
7	So. Cent. Franchise Arbitration	201,002	8,428	402	57,677	151,753
8						
9	FMS Solution Store Sell	161,771	17,995	402	14,700	165,066
10						
11	Dominion Storm Support		1,754,353	402	19,690	1,734,663
12						
13	VACATION PAY ACCRUAL	4,701,188	3,086,359			7,787,547
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	11,041,003				12,913,205

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

FOOTNOTE DATA

Schedule Page: 233 Line No.: 49 Column: b

Certain 2002 amounts were reclassifed to conform to 2003 presentations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	UNBILLED REVENUE	17,719,000	17,578,000
3	LIFE/MEDICAL BENEFITS	58,137,000	61,783,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	18,331,000	15,990,000
5	REGULATORY LIABILITY	32,322,000	27,815,000
6	NUCLEAR DECOMMISSIONING	28,564,000	30,463,000
7	Other	-18,274,065	-19,675,696
8	TOTAL Electric (Enter Total of lines 2 thru 7)	136,798,935	133,953,304
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	136,798,935	133,953,304

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	60,000,000		
2	Total Common Stock	60,000,000		
3	Cumulative Preferred Stock	4,000,000		
4	4.00% Series		100.00	104.25
5	4.60% Series		100.00	103.25
6	4.75% Series		100.00	102.00
7	4.40% Series		100.00	102.00
8	4.58% Series		100.00	101.00
9	Cumulative Preferred Stock	5,000,000		
10	Preference Stock	1,000,000	100.00	
11	Total Preferred Stock	10,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
100	354,405,315					1
100	354,405,315					2
						3
39,980	3,998,000					4
39,997	3,999,700					5
80,000	8,000,000					6
75,000	7,500,000					7
99,990	9,999,000					8
						9
						10
334,967	33,496,700					11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 211 - MISCELLANEOUS PAID IN CAPITAL	
2	Donations by General Gas & Electric Corporation (Former Parent)	419,213
3	Excess of Stated Value of 3,000,000 shares of Common Stock	
4	exchanged for 857,143 shares of $7.50 par value Common Stock and	
5	miscellaneous adjustments applicable to exchange	326,032
6	Excess of Net Worth of Assets at date of Merger (12/31/43)	
7	over stated value of Common Stock issued therefor	1,167,518
8	Florida Public Service 4% Series "C" Bonds with called premium	
9	and interest held by General Gas and Electric Corporation	65,210
10	Reversal of over accrual of Federal Income Tax applicable to	
11	period prior to January 1, 1944	262,837
12	Transfer from Earned Surplus amount equivalent to Preferred Stock	
13	Dividends prior to 12/31/43 which on an accrual basis were	
14	applicable to 1944	92,552
15	To write off unamortized debt discount, premium and expense	
16	applicable to Bonds refunded in prior years	-979,793
17	Adjustment of orginal cost of Florida Public Service Company	
18	resulting from examination by Federal Power Commission	-63,027
19	Adjustment in carrying value of Georgia Power & Light Company Common	
20	Stock occasioned by the subsidiary company's increase in capital	
21	surplus	33,505
22	Capital Contribution from Parent Company	725,451,989
23	Other miscellaneous adjustments	45,211
24	SUBTOTAL MISCELLANEOUS PAID IN CAPITAL	726,821,247
25		
26		
27		
28		
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37		
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39		
40	TOTAL	726,821,247

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FIRST MORTGAGE BONDS - 6.65%	300,000,000	3,182,657
2			429,000 D
3	FIRST MORTGAGE BONDS - 8%	150,000,000	1,197,619
4	(SEE NOTE 1)		751,180 D
5	FIRST MORTGAGE BONDS - 6 7/8%	80,000,000	765,503
6			1,069,599 D
7	FIRST MORTGAGE BONDS - 6 1/8%	70,000,000	521,110
8			759,659 D
9	FIRST MORTGAGE BONDS - 6%	110,000,000	2,623,337
10			3,065,699 D
11	FIRST MORTGAGE BONDS - 7%	100,000,000	933,448
12	(SEE NOTE 1)		625,000 D
13	FIRST MORTGAGE BONDS - 4.8%	425,000,000	5,293,254
14	(SEE NOTE 1)		1,513,000 D
15	FIRST MORTGAGE BONDS - 5.9%	225,000,000	3,394,376
16	(SEE NOTE 1)		571,500 D
17	FIRST MORTGAGE BONDS - 5.1%	300,000,000	3,317,476
18	(SEE NOTE 1)		594,000 D
19	MEDIUM TERM NOTE (SEBRING) - 6.67%	30,700,000	280,604
20			
21	MEDIUM TERM NOTE - 6.62%	35,000,000	194,581
22			
23	MEDIUM TERM NOTE - 6.69%	40,000,000	242,220
24			
25	MEDIUM TERM NOTE - 6.72%	45,000,000	272,183
26			
27	MEDIUM TERM NOTE - 6.77%	45,000,000	271,939
28			
29	MEDIUM TERM NOTE - 6.81%	85,000,000	534,680
30			
31	MEDIUM TERM NOTE - 6.75%	150,000,000	5,528,498
32			436,500 D
33	TOTAL	2,431,565,000	43,563,485

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
071801	071511	071501	171511	300,000,000	19,839,167	1
						2
121592	120122	121592	120122		2,766,667	3
						4
020993	020108	020993	020108	80,000,000	5,499,999	5
						6
031093	030103	031093	030103		714,582	7
						8
072093	070103	072093	070103		3,300,000	9
						10
121593	120123	121593	120123		6,416,471	11
						12
021803	030113	021803	030113	425,000,000	17,566,667	13
						14
021803	030133	021803	030133	225,000,000	11,431,250	15
						16
112103	120115	112103	120115	300,000,000	1,700,000	17
						18
042093	040108	042093	040108	14,500,000	1,047,189	19
						20
070197	070103	070197	070103		1,158,500	21
						22
070197	070104	070197	070104	40,000,000	2,676,000	23
						24
070197	070105	070197	070105	45,000,000	3,024,000	25
						26
070197	070106	070197	070106	45,000,000	3,046,500	27
						28
070197	070107	070197	070107	85,000,000	5,788,500	29
						30
021098	020128	021098	020128	150,000,000	10,125,000	31
						32
				1,950,365,000	98,439,728	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	POLLUTION CONTROL BONDS (CITRUS) 2002A	108,550,000	2,356,705
2	POLLUTION CONTROL BONDS (CITRUS) 2002B	100,115,000	2,081,983
3	POLLUTION CONTROL BONDS (CITRUS) 2002C	32,200,000	756,175
4			
5	NOTE 1 - AUTHORIZED BY DOCKET NO. 021029-EI, ORDER NO.		
6	PSC-02-1631-FOF-EI, ISSUED 11-25-02.		
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33	TOTAL	2,431,565,000	43,563,485

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
080102	010127	080102	010127	108,550,000	1,074,464	1
070102	010122	070102	010122	100,115,000	949,257	2
080102	010118	080102	010118	32,200,000	315,515	3
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						30
						31
						32
				1,950,365,000	98,439,728	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	296,354,489
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax Deducted for Books	123,078,180
11		
12	Deductions Recorded on Books Not Deducted for Return	499,654,416
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Deductions on Return Not Charged Against Book Income	-421,834,730
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	497,252,355
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	174,038,324
30	True up Entries and Other Tax Benefits	-28,580,144
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	145,458,180
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES					
2	FICA	-715,804		22,784,866	22,069,169	
3	Unemployment	73,942		289,776	363,718	
4	Highway Use			34,004	34,004	
5	Superfund					
6	Income	14,689,303		145,458,180	145,421,696	
7	Income Tax Subsidiary					
8	Special Fuels	-1,299,572			-4,470	
9						
10						
11	STATE TAXES					
12	Income	9,782,364		26,734,925	31,461,997	
13	Income Tax Subsidiary					
14	Gross Receipts	5,028,637		68,919,873	68,587,575	
15	Licenses-Vehicles					
16	Hauling Permit-Escrow					
17	Licenses-HP					
18	Documentary Stamps					
19	Unemployment	474,171		1,927,742	2,402,031	
20	Intangibles			6,792	6,792	
21	Filing Fee					
22	Regulatory Assessment	1,041,392		2,056,654	2,016,332	
23	Sales Tax-Telecomm	-110,797		20,233	-90,564	
24	Sales Tax-Duplicating					
25	Sales Tax Registration Fee					
26	Sales Tax-Company Use	14,960		179,842	180,444	
27	Special Fuels					
28						
29	COUNTY & LOCAL TAXES					
30	Property-County & Local			80,733,479	80,733,479	
31	Licenses-Occup-County &					
32	Special Fuels-County			8,813	8,813	
33	Sales Tax-County Telecomm					
34	Sales Tax-County Duplicating					
35	Franchise-Local	4,868,435		66,753,285	66,590,332	
36	Property-Local					
37	Licenses-Occup/Misc/Local					
38						
39						
40	Adj-Use Tax on Purchases					
41	TOTAL	33,847,031		415,908,464	419,781,348	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-107		22,573,684			211,182	2
					289,776	3
		34,004				4
						5
14,725,787		160,594,108			-15,135,928	6
						7
-1,295,102						8
						9
						10
						11
5,055,291		27,833,613			-1,098,688	12
						13
5,360,936		68,919,873				14
						15
						16
						17
						18
-118					1,927,742	19
		6,792				20
						21
1,081,714		2,056,654				22
		20,233				23
						24
						25
14,358		179,842				26
						27
						28
						29
		80,581,658			151,821	30
						31
		8,813				32
						33
						34
5,031,389		66,753,285				35
						36
						37
						38
						39
						40
29,974,148		429,562,559			-13,654,095	41

Schedule Page: 262 Line No.: 40 Column: b

Page 112, Line 39, Columns c & d

The difference between the taxes accrued amount on page 112, line 39 and taxes accrued on page 262 - 263, Col. (b) & (g) are for exclusions of sales taxes per instruction #1 on page 262.

	Balance at Beginning of Year	Balance at End of Year
Taxes Accrued, P.112, Line 39	33,517,521	30,152,914
State Sales Tax on Purchases	329,798	(174,800)
County Sales Tax on Purchases	(288)	(3,966)
	33,847,031	29,974,148

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	212,761			4114001	212,761	
4	7%						
5	10%	47,209,747			4114001	5,858,239	
6							
7							
8	TOTAL	47,422,508				6,071,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
41,351,508	27 years		5
			6
			7
41,351,508			8
			9
			10
			11
			12
			13
			14
			15
			16
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Florida Municipal Power Authority	1,140,000	131	180,000		960,000
2	SECI	3,300,000			580,000	3,880,000
3	Deferred rent expense	974,915	various	972,842	630,249	632,322
4	Deferred expense Joint Owners CR3	599,194	143	852,661	899,840	646,373
5	Deferred exit costs		131	968,934	3,939,009	2,970,075
6	Miscellaneous deposits	1,519,884	131	44,864	10,500	1,485,520
7	Various	1,271,011	various	4,356,776	3,916,222	830,457
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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45						
46						
47	TOTAL	8,805,004		7,376,077	9,975,820	11,404,747

Schedule Page: 269 Line No.: 6 Column: b

Certain 2002 amounts were presented separately to conform to 2003 presentations.

Schedule Page: 269 Line No.: 7 Column: b

Certain 2002 amounts were presented differently to conform with 2003 presentations.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	8,186,000		1,004,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	8,186,000		1,004,000
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	8,186,000		1,004,000
18	Classification of TOTAL			
19	Federal Income Tax	7,019,000		861,000
20	State Income Tax	1,167,000		143,000
21	Local Income Tax			

NOTES

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						7,182,000	4
							5
							6
							7
						7,182,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						7,182,000	17
							18
						6,158,000	19
						1,024,000	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	419,039,000	3,714,000	27,836,000
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	419,039,000	3,714,000	27,836,000
6	Other	-379,000		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	418,660,000	3,714,000	27,836,000
10	Classification of TOTAL			
11	Federal Income Tax	359,661,000	3,235,000	22,980,000
12	State Income Tax	58,999,000	479,000	4,856,000
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
						394,917,000	2
							3
							4
						394,917,000	5
7,573,000						7,194,000	6
							7
							8
7,573,000						402,111,000	9
							10
6,493,000						346,409,000	11
1,080,000						55,702,000	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - FAS 109	44,903,000		887,000
4				
5				
6				
7	OCI / Minimum Pension Liabilit	-1,486,200		
8	Other	1,460,000	35,980,000	30,197,000
9	TOTAL Electric (Total of lines 3 thru 8)	44,876,800	35,980,000	31,084,000
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	44,876,800	35,980,000	31,084,000
20	Classification of TOTAL			
21	Federal Income Tax	38,496,000	30,852,000	26,733,000
22	State Income Tax	6,380,800	5,128,000	4,351,000
23	Local Income Tax			

NOTES

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
						44,016,000	3
							4
							5
							6
		219309D	2,326,693	219309D	1,486,200	-2,326,693	7
						7,243,000	8
			2,326,693		1,486,200	48,932,307	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			2,326,693		1,486,200	48,932,307	19
							20
			2,161,599		1,381,000	41,834,401	21
			165,094		105,200	7,097,906	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (Details) called for concerning other regulatory liabilities which are created through the rate-making actions of regulatory agencies (and not includable in other amounts)
2. For regulatory Liabilities being amortized show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is Less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	Accumulated Deferred Taxes - FAS 109	4111000	11,898,000	212,000	72,104,000
2	Period of Amortization occurs as temporary				
3	differences occur.				
4					
5	Deferred Capacity Revenue	5572001	1,492,284	10,888,114	9,395,830
6					
7	OPEBS Liability - Wholesale	9260001	93,092	53,876	20,203
8					
9	Auctioned S02 Allowance			444,765	1,707,393
10					
11	ARO Nuclear Decom Trust Unrealized Gains	1289191	6,302,812	111,718,655	105,415,843
12	ARO SFAS 143 Nuclear Decommissioning	4073002	12,153,846	20,077,172	7,923,326
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41	TOTAL		31,940,034	143,394,582	196,566,595

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,691,228,328	1,627,049,640
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	740,412,983	720,002,777
5	Large (or Ind.) (See Instr. 4)	218,648,600	206,724,798
6	(444) Public Street and Highway Lighting	1,303,566	1,260,335
7	(445) Other Sales to Public Authorities	179,215,536	169,206,791
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,830,809,013	2,724,244,341
11	(447) Sales for Resale	228,334,215	230,362,904
12	TOTAL Sales of Electricity	3,059,143,228	2,954,607,245
13	(Less) (449.1) Provision for Rate Refunds	36,332,666	5,390,945
14	TOTAL Revenues Net of Prov. for Refunds	3,022,810,562	2,949,216,300
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,388,053	8,385,102
17	(451) Miscellaneous Service Revenues	20,647,127	18,805,086
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	56,020,586	52,450,042
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	32,966,852	53,876,351
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	118,022,618	133,516,581
27	TOTAL Electric Operating Revenues	3,140,833,180	3,082,732,881

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ELECTRIC OPERATING REVENUES (Account 400)

4. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increase or decreases.
6. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
19,428,943	18,753,816	1,331,914	1,301,515	2
				3
11,552,967	11,420,084	154,294	150,577	4
4,000,559	3,835,061	2,643	2,535	5
28,629	28,297	1,917	1,965	6
2,945,604	2,822,089	19,726	19,169	7
				8
				9
37,956,702	36,859,347	1,510,494	1,475,761	10
4,322,616	4,179,607	22	22	11
42,279,318	41,038,954	1,510,516	1,475,783	12
				13
42,279,318	41,038,954	1,510,516	1,475,783	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SERVICE	19,428,943	1,691,228,328	1,331,914	14,587	0.0870
2						
3	COMMERCIAL AND IND SERVICE	15,553,526	959,061,583	156,937	99,107	0.0617
4						
5	PUBLIC STREET AND HIGHWAY					
6	LIGHTING	28,629	1,303,566	1,917	14,934	0.0455
7						
8	OTHER SALES TO PUBLIC					
9	AUTHORIITIES	2,945,604	179,215,536	19,726	149,326	0.0608
10						
11	TOTAL SALES TO ULTIMATE	37,956,702	2,830,809,013	1,510,494	25,129	0.0746
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	REQUIREMENTS SERVICE:					
2	CITY OF BARTOW	RQ	TARIFF NO. 9	49	49	48
3	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	5	5	5
4	CITY OF HAVANA	RQ	FERC NO. 115	3	3	3
5	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	15	15	15
6	CITY OF KISSIMMEE	RQ	FERC NO. 120	0	0	0
7	CITY OF MOUNT DORA	RQ	FERC NO. 127	19	19	19
8	CITY OF NEWBERRY	RQ	FERC NO. 116	5	5	5
9	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	15	15	15
10	CITY OF QUINCY	RQ	TARIFF NO. 1	19	19	19
11	CITY OF ST CLOUD	RQ	FERC NO. 121	0	0	0
12	CITY OF TALLAHASSEE	RQ	FERC NO. 178	11	11	11
13	CITY OF WILLISTON	RQ	FERC NO. 124	6	6	6
14	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	30	38	23
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
293,708	6,276,452	8,709,341	18,720	15,004,513	2
34,957	685,541	1,229,116	3,168	1,917,825	3
8,309	208,180	350,589	1,320	560,089	4
131,287	2,520,000	3,495,689		6,015,689	5
			8,004	8,004	6
88,486	1,948,110	3,176,931	2,904	5,127,945	7
27,138	624,503	1,100,186	3,168	1,727,857	8
102,117	1,876,560	3,327,101	996	5,204,657	9
111,919	2,172,127	3,915,664	6,336	6,094,127	10
			996	996	11
99,863		4,031,044		4,031,044	12
31,747	697,471	1,141,166	3,168	1,841,805	13
150,262	4,454,416	5,332,333	71,040	9,857,789	14
3,359,432	72,337,306	117,053,338	236,122	189,626,766	
963,184	0	39,056,158	-348,709	38,707,449	
4,322,616	**72,337,306**	**156,109,496**	**-112,587**	**228,334,215**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	FLORIDA POWER AND LIGHT	RQ	TARIFF NO. 9	163	163	163
2	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	0	0	0
3	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	738	738	741
4	SOUTHEASTERN PWER ADMIN	RQ	FERC NO. 65	14	14	14
5	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 7	150	150	150
6						
7						
8	NON-REQUIREMENTS SERVICE					
9	ALABAMA ELECTRIC CO-OP	OS	FERC NO.148	N/A	N/A	N/A
10	AMERICAN ELECTRIC POWER CO	OS	FERC NO. 9	N/A	N/A	N/A
11	CARGILL-ALLIANT, LLC (1)	OS	FERC NO. 8	N/A	N/A	N/A
12	COBB ELECTRIC MEMBERSHIIP CORP	OS	FERC NO. 10	N/A	N/A	N/A
13	CONSTELLATION POWER SOURCE, INC.	OS	FERC NO. 154	N/A	N/A	N/A
14	DTE ENERGY TRADING	OS	FERC NO. 176	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
998,552	20,056,500	25,464,185		45,520,685	1
			25,488	25,488	2
966,308	25,915,046	43,505,931	90,814	69,511,791	3
16,679	402,400	457,193		859,593	4
298,100	4,500,000	11,816,869		16,316,869	5
					6
					7
					8
2,650		98,051		98,051	9
2,925		168,396		168,396	10
67,744		2,523,356		2,523,356	11
11,008		444,472		444,472	12
1,173		53,329		53,329	13
200		11,089		11,089	14
3,359,432	72,337,306	117,053,338	236,122	189,626,766	
963,184	0	39,056,158	-348,709	38,707,449	
4,322,616	**72,337,306**	**156,109,496**	**-112,587**	**228,334,215**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	DUKE ENERGY TRADING & MKTG INC (1)	OS	FERC NO. 6	N/A	N/A	N/A
2	DYNEGY (1)	OS	FERC NO. 156	N/A	N/A	N/A
3	ENTERGY SERVICES INC. (1)	OS	FERC NO. 8	N/A	N/A	N/A
4	ENTERGY-KOCH TRADING, LP	OS	FERC NO. 8	N/A	N/A	N/A
5	EXELON GENERATION CO. LLC	OS	FERC NO. 10	N/A	N/A	N/A
6	FLORIDA MUNICIPAL POWER AGENCY	OS	FERC NO. 105	N/A	N/A	N/A
7	FLORIDA POWER & LIGHT CO (1)	OS	FERC NO. 81/02	N/A	N/A	N/A
8	HOMESTEAD, CITY OF (1)	OS	FERC NO. 82	N/A	N/A	N/A
9	LAKELAND, CITY OF (1)	OS	FERC NO. 92	N/A	N/A	N/A
10	L.G.& E. POWER ENERGY MKTG. (1)	OS	FERC NO. 157	N/A	N/A	N/A
11	MORGAN STANLEY CAPITAL GROUP (1)	OS	FERC NO. 177	N/A	N/A	N/A
12	NEW SMYMA BEACH, CITY OF (3)	OS	FERC NO. 104	N/A	N/A	N/A
13	OGLETHORPE (1)	OS	FERC NO. 139	N/A	N/A	N/A
14	ORLANDO UTILITIES COMMISSION (2)	OS	FERC NO. 86	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,543		169,546		169,546	1
20		454		454	2
200		6,913		6,913	3
17,881		802,668		802,668	4
350		15,015		15,015	5
7,716		349,546		349,546	6
76,307		2,517,120		2,517,120	7
4,278		167,703		167,703	8
4,525		171,353		171,353	9
80,607		3,533,282		3,533,282	10
893		35,390		35,390	11
23,333		1,296,219		1,296,219	12
37,814		1,416,636		1,416,636	13
86,197		2,973,227		2,973,227	14
3,359,432	72,337,306	117,053,338	236,122	189,626,766	
963,184	0	39,056,158	-348,709	38,707,449	
4,322,616	**72,337,306**	**156,109,496**	**-112,587**	**228,334,215**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	REEDY CREEK UTILITIES (1)	OS	FERC NO. 119	N/A	N/A	N/A
2	SEMINOLE ELECTRIC COOP INC. (1)	OS	FERC NO. 128	N/A	N/A	N/A
3	SOUTH CAROLINA ELEC & GAS CO	OS	FERC NO. 8/10	N/A	N/A	N/A
4	SOUTHERN SERVICES, INC (1)	OS	FERC NO. 111	N/A	N/A	N/A
5	TALLAHASSEE, CITY OF (2)	OS	FERC NO. 122	N/A	N/A	N/A
6	TAMPA ELECTRIC CO (2)	OS	FERC NO. 80	N/A	N/A	N/A
7	TENNESSEE VALLEY AUTHORITY	OS	FERC NO. 138	N/A	N/A	N/A
8	THE ENERGY AUTHORITY (1)	OS	FERC NO. 175	N/A	N/A	N/A
9	VIRGINIA ELECTRIC & POWER COMPANY	OS	FERC NO. 9	N/A	N/A	N/A
10						
11						
12	GAIN ON ECONOMY SALES - 20%					
13	CREDIT SCHEDULE H CAPACITY SALES					
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
14,974		406,823		406,823	1
119,472		5,017,509		5,017,509	2
16,252		757,059		757,059	3
43,204		2,151,149		2,151,149	4
20,347		737,970		737,970	5
205,452		8,526,076		8,526,076	6
53,520		2,509,763		2,509,763	7
61,450		2,187,144		2,187,144	8
149		8,900		8,900	9
					10
					11
			-306,405	-306,405	12
			-42,304	-42,304	13
					14
3,359,432	72,337,306	117,053,338	236,122	189,626,766	
963,184	0	39,056,158	-348,709	38,707,449	
4,322,616	**72,337,306**	**156,109,496**	**-112,587**	**228,334,215**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 2 Column: j
Column J consists of Customer Charges and/or Facility Charges.

Schedule Page: 310.1 Line No.: 3 Column: j
SECI Column J includes billing contraints.

Schedule Page: 310.1 Line No.: 11 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 1 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 2 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 3 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 7 Column: a
OS (1) ECONOMY INTERCHANGES SALES.

Schedule Page: 310.2 Line No.: 8 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 9 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 10 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 11 Column: a
OS (1) ECONOMY INERCHANGE SALES.

Schedule Page: 310.2 Line No.: 12 Column: a
OS (3) REGULATION SERVICE.

Schedule Page: 310.2 Line No.: 13 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.2 Line No.: 14 Column: a
OS (2) ECONOMY AND EMERGENCY INTERCHANGE SALES.

Schedule Page: 310.3 Line No.: 1 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.3 Line No.: 2 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.3 Line No.: 4 Column: a
OS (1) ECONOMY INTERCHANGE SALES.

Schedule Page: 310.3 Line No.: 5 Column: a
OS (2) ECONOMY AND EMERGENCY INTERCHANGE SALES.

Schedule Page: 310.3 Line No.: 6 Column: a
OS (2) ECONOMY AND EMERGENCY INTERCHANGE SALES.

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec 31, 2003

FOOTNOTE DATA

Schedule Page: 310.3 Line No.: 8 Column: a

OS (1) ECONOMY INTERCHANGE SALES.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,475,385	2,173,197
5	(501) Fuel	670,920,726	575,938,585
6	(502) Steam Expenses	7,612,276	6,701,641
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	262	-64,788
10	(506) Miscellaneous Steam Power Expenses	22,165,759	21,825,624
11	(507) Rents		
12	(509) Allowances	7,472,794	8,933,684
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	709,647,202	615,507,943
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,147,990	3,238,808
16	(511) Maintenance of Structures	1,436,815	938,726
17	(512) Maintenance of Boiler Plant	4,721,341	12,240,469
18	(513) Maintenance of Electric Plant	5,093,981	2,715,351
19	(514) Maintenance of Miscellaneous Steam Plant	28,083,021	15,970,899
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	42,483,148	35,104,253
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	752,130,350	650,612,196
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	136,291	211,471
25	(518) Fuel	31,099,846	31,990,432
26	(519) Coolants and Water	2,872,185	2,930,964
27	(520) Steam Expenses	10,832,476	8,618,425
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		1,910
31	(524) Miscellaneous Nuclear Power Expenses	30,564,003	33,074,266
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	75,504,801	76,827,468
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	7,442,687	14,050,181
36	(529) Maintenance of Structures	7,179,095	1,527,698
37	(530) Maintenance of Reactor Plant Equipment	11,799,427	11,402,843
38	(531) Maintenance of Electric Plant	3,425,070	1,441,375
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,288,427	1,652,552
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	32,134,706	30,074,649
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	107,639,507	106,902,117
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	7,465,422	2,716,089
63	(547) Fuel	358,414,714	266,085,286
64	(548) Generation Expenses	3,605,291	727,174
65	(549) Miscellaneous Other Power Generation Expenses	5,519,822	8,556,445
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	375,005,249	278,084,994
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,027,809	3,190,054
70	(552) Maintenance of Structures	407,891	836,044
71	(553) Maintenance of Generating and Electric Plant	1,905,012	4,946,163
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	16,556,866	15,193,089
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	19,897,578	24,165,350
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	394,902,827	302,250,344
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	551,700,391	507,883,865
77	(556) System Control and Load Dispatching	4,889,040	4,532,020
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	556,589,431	512,415,885
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,811,262,115	1,572,180,542
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,599,592	2,617,037
84	(561) Load Dispatching	338,664	400,102
85	(562) Station Expenses	159,296	509,766
86	(563) Overhead Lines Expenses	52,708	56,406
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others		1,177,877
89	(566) Miscellaneous Transmission Expenses	12,831,158	15,408,492
90	(567) Rents		
91	TOTAL Operation (Enter Total of lines 83 thru 90)	15,981,418	20,169,680
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	-3,764	6,675
94	(569) Maintenance of Structures	203,137	681
95	(570) Maintenance of Station Equipment	2,152,286	3,750,464
96	(571) Maintenance of Overhead Lines	8,580,863	7,489,711
97	(572) Maintenance of Underground Lines		203
98	(573) Maintenance of Miscellaneous Transmission Plant	745,032	81,468
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	11,677,554	11,329,202
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	27,658,972	31,498,882
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	5,385,246	6,252,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	2,137,262	
106	(582) Station Expenses	323,753	423,455
107	(583) Overhead Line Expenses	3,202,161	5,124,045
108	(584) Underground Line Expenses	232	640,056
109	(585) Street Lighting and Signal System Expenses	4,212,181	2,812,260
110	(586) Meter Expenses	9,447,706	7,234,840
111	(587) Customer Installations Expenses	525,559	530,216
112	(588) Miscellaneous Expenses	30,984,970	43,827,158
113	(589) Rents	66,519	476,191
114	TOTAL Operation (Enter Total of lines 103 thru 113)	56,285,589	67,320,752
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	189,616	419,750
117	(591) Maintenance of Structures	108,994	-43,849
118	(592) Maintenance of Station Equipment	1,419,548	1,039,925
119	(593) Maintenance of Overhead Lines	19,547,487	12,326,557
120	(594) Maintenance of Underground Lines	304,828	33,940
121	(595) Maintenance of Line Transformers	643,245	64,978
122	(596) Maintenance of Street Lighting and Signal Systems	639	129,825
123	(597) Maintenance of Meters	953	34,638
124	(598) Maintenance of Miscellaneous Distribution Plant	14,462,968	625,363
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	36,678,278	14,631,127
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	92,963,867	81,951,879
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	1,109,527	3,227,060
130	(902) Meter Reading Expenses	8,429,685	8,362,661
131	(903) Customer Records and Collection Expenses	22,668,540	23,544,661
132	(904) Uncollectible Accounts	4,812,023	3,345,054
133	(905) Miscellaneous Customer Accounts Expenses	10,550,102	12,913,453
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	47,569,877	51,392,889
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		1,570
138	(908) Customer Assistance Expenses	62,811,069	66,587,439
139	(909) Informational and Instructional Expenses	2,513,239	1,093,438
140	(910) Miscellaneous Customer Service and Informational Expenses	102,716	93,712
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	65,427,024	67,776,159
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	5,158	76,011
145	(912) Demonstrating and Selling Expenses	1,410,985	2,569,029
146	(913) Advertising Expenses	1,589,706	
147	(916) Miscellaneous Sales Expenses	1,500,491	2,637,653
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	4,506,340	5,282,693
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	54,268,380	34,832,467
152	(921) Office Supplies and Expenses	27,268,477	34,041,184
153	(Less) (922) Administrative Expenses Transferred-Credit		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	24,452,213	33,426,752
156	(924) Property Insurance	9,766,201	6,717,231
157	(925) Injuries and Damages	7,957,680	5,181,820
158	(926) Employee Pensions and Benefits	56,558,515	23,587,738
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses		1,133,894
161	(929) (Less) Duplicate Charges-Cr.	2,708,646	1,042,767
162	(930.1) General Advertising Expenses	3,094,063	1,937,284
163	(930.2) Miscellaneous General Expenses	6,977,015	55,669
164	(931) Rents	8,946,440	6,646,314
165	TOTAL Operation (Enter Total of lines 151 thru 164)	196,580,338	146,517,586
166	Maintenance		
167	(935) Maintenance of General Plant	-3,973,176	6,468,132
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	192,607,162	152,985,718
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	2,241,995,357	1,963,068,762

Schedule Page: 320 Line No.: 78 Column: c

As a result of the latest FERC compliance audit, all expenses associated with deferred fuel expense have been reclassed from accounts 55799 and 55798 to either regulatory debits or regulatory credits.

The interest associated with the deferred fuel has been reclassed to other income in FERC accounts 431xx.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	FERC NO. 65	N/A	N/A	N/A
3	GLADES ELECTRIC COOPERATIVE INC.	OS	*	N/A	N/A	N/A
4	BAY COUNTY (1)	OS	COG	9	10	8
5	BAY COUNTY (1)	AD	COG	N/A	N/A	N/A
6	US AGRI-CHEMICALS CORPORATION (1)	OS	COG	6	15	5
7	US AGRI-CHEMICALS CORPORATION (1)	AD	COG	N/A	N/A	N/A
8	PINELLAS COUNTY (1)	OS	COG	49	57	47
9	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
10	AUBURNDALE COGENERATOR (1)	OS	COG	131	157	140
11	AUBURNDALE COGENERATOR (1)	AD	COG	N/A	N/A	N/A
12	TIMBER ENERGY RESOURCES, INC. (1)	OS	COG	10	13	11
13	TIMBER ENERGY RESOURCES, INC. (1)	AD	COG	N/A	N/A	N/A
14	PASCO COUNTY (1)	OS	COG	22	26	22
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
47,542				849,755		849,755	2
82				8,084		8,084	3
73,944			2,638,680	1,555,835		4,194,515	4
					29,685	29,685	5
52,985			525,096	2,522,007		3,047,103	6
					-23,170	-23,170	7
409,778			21,529,890	8,607,622		30,137,512	8
					260,148	260,148	9
1,048,001			31,700,771	32,021,692		63,722,463	10
1					274,580	274,580	11
85,978			1,600,930	1,504,615		3,105,545	12
					-200,836	-200,836	13
190,995			9,044,520	4,113,047		13,157,567	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
2	CARGILL FERTILIZER (1)	OS	COG	14	33	14
3	CARGILL FERTILIZER (1)	AD	COG	N/A	N/A	N/A
4	DADE COUNTY (1)	OS	COG	33	50	34
5	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
6	LAKE COGEN LIMITED (1)	OS	COG	102	108	100
7	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	PASCO COGEN LIMITED (1)	OS	COG	100	117	93
9	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
10	ORLANDO COGEN LIMITED (1)	OS	COG	78	96	81
11	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
12	RIDGE GENERATING STATION (1)	OS	COG	30	39	24
13	RIDGE GENERATINIG STATION (1)	AD	COG	N/A	N/A	N/A
14	POLK POWER PARTNERS (1)	OS	COG	102	111	99
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					106,807	106,807	1
90,813			5,459,400	1,947,766		7,407,166	2
					90,798	90,798	3
280,007			10,000,008	8,573,365		18,573,373	4
					68,225	68,225	5
449,050			27,555,882	16,272,070		43,827,952	6
					71,951	71,951	7
544,733			35,219,836	13,270,363		48,490,199	8
					38,886	38,886	9
691,027			21,011,501	21,492,600		42,504,101	10
					197,459	197,459	11
162,218			7,266,207	5,443,446		12,709,653	12
					-132,332	-132,332	13
453,839			37,448,701	9,790,617		47,239,318	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
2	ORANGE COGEN LIMITED (1)	OS	COG	75	105	66
3	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	JEFFERSON POWER L.C. (1)	OS	COG	3	5	1
5	JEFFERSON POWER L.C. (1)	AD	COG	N/A	N/A	N/A
6	CITRUS WORLD (1)	OS	COG	N/A	N/A	N/A
7	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
8	LAKE COUNTY (1)	OS	COG	10	14	10
9	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
10	PCS PHOSPHATE (1)	OS	COG	N/A	N/A	N/A
11	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
12						
13	INTERCHANGE POWER:					
14	SOUTHERN SERVICES INC. (2)	OS	FERC NO.111	N/A	N/A	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-149,877	-149,877	1
394,574			23,600,280	12,151,596		35,751,876	2
					97,573	97,573	3
10,810			484,466	298,883		783,349	4
					8,281	8,281	5
118				4,987		4,987	6
-10					-492	-492	7
82,600			5,013,810	1,783,391		6,797,201	8
					60,264	60,264	9
1,049				52,198		52,198	10
-264					-11,999	-11,999	11
							12
							13
18,257				858,631		858,631	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SOUTHERN SERVICES INC. (2)	AD	FERC NO. 111	N/A	N/A	N/A
2	SOUTHERN SERVICES INC.	LF	FERC NO. 70	413	413	**
3	SOUTHERN SERVICES INC.	AD	FERC NO. 70	N/A	N/A	N/A
4	FLORIDA POWER & LIGHT CO. (3)	OS	FERC NO. 81	N/A	N/A	N/A
5	FLORIDA POWER & LIGHT CO. (3)	AD	FERC NO. 81	N/A	N/A	N/A
6	TAMPA ELECTRIC CO. (3)	OS	FERC NO. 80	N/A	N/A	N/A
7	TAMPA ELECTRIC CO. (3)	AD	FERC NO. 80	N/A	N/A	N/A
8	TAMPA ELECTRIC CO.	LF	FERC NO. 80	60	60	**
9	TAMPA ELECTRIC CO.	AD	FERC NO. 80	N/A	N/A	N/A
10	ORLANDO UTILITIES COMMISSION (2)	OS	FERC NO.86	N/A	N/A	N/A
11	CITY OF TALLAHASSEE (2)	OS	FERC NO. 122	N/A	N/A	N/A
12	CITY OF TALLAHASSEE (2)	AD	FERC NO.122	N/A	N/A	N/A
13	CARGILL-ALLIANT, LLC (2)	OS	FERC NO. 8	N/A	N/A	N/A
14	COBB ELECTRIC MEMBERSHIP CORP. (2)	OS	FERC NO. 10	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					8,886	8,886	1
3,332,363			48,443,417	55,810,612		104,254,029	2
					720,071	720,071	3
20,475				1,334,978		1,334,978	4
					-392	-392	5
1,289				311,257		311,257	6
					369	369	7
290,919			6,786,804	11,372,826		18,159,630	8
					119,939	119,939	9
29,515				2,304,640		2,304,640	10
9,601				579,536		579,536	11
					-3	-3	12
16,313				944,824		944,824	13
65,138				2,623,133		2,623,133	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	OGLETHORPE POWER CORP. (2)	OS	FERC NO.139	N/A	N/A	N/A
2	CALPINE ENERGY SVCS., L.P.	OS	FERC NO.170/10	N/A	N/A	N/A
3	DUKE ENERGY (2)	OS	FERC NO. 6	N/A	N/A	N/A
4	DUKE ENERGY (2)	AD	FERC NO. 6	N/A	N/A	N/A
5	SEMINOLE ELECTRIC COOP. INC. (2)	OS	FERC NO.128	N/A	N/A	N/A
6	SEMINOLE ELECTRIC COOP. INC. (2)	AD	FERC NO.128	N/A	N/A	N/A
7	JACKSONVILLE ELECTRIC AUTHORITY (3)	OS	FERC NO. 91	N/A	N/A	N/A
8	JACKSONVILLE ELECTRIC AUTHORITY (3)	AD	FERC NO. 91	N/A	N/A	N/A
9	KOCH POWER SERVICES (2)	OS	FERC NO. 159	N/A	N/A	N/A
10	CITY OF LAKELAND (2)	OS	FERC NO. 92	N/A	N/A	N/A
11	DYNEGY INC. (2)	OS	FERC NO. 156	N/A	N/A	N/A
12	MUNICIPAL ELEC. AUTHORITY OF GA (2)	OS	FERC VOL NO. 3	N/A	N/A	N/A
13	RELIANT ENERGY SERVICES INC. (2)	OS	FERC NO. 167	N/A	N/A	N/A
14	L.G. & E. POWER MKTG. (2)	OS	FERC NO.157	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
15,385				603,059		603,059	1
1,180				59,325		59,325	2
7,650				340,017		340,017	3
					-789	-789	4
64,562				3,384,411		3,384,411	5
					32	32	6
				3,057,820		3,057,820	7
					7,824	7,824	8
							9
13,005				880,843		880,843	10
28,741				1,164,937		1,164,937	11
							12
154,687				15,430,200		15,430,200	13
136,946				4,690,799		4,690,799	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	REEDY CREEK (2)	OS	FERC NO.119	N/A	N/A	N/A
2	CORAL POWER (2)	OS	FERC NO.173	N/A	N/A	N/A
3	CONOCO PHILLIPS CO	OS	FERC NO.	N/A	N/A	N/A
4	MORGAN STANLEY CAPITAL GROUP (2)	OS	FERC NO.177	N/A	N/A	N/A
5	CITY OF NEW SMYRNA BEACH (2)	AD	FERC NO. 104	N/A	N/A	N/A
6	THE ENERGY AUTHORITY (2)	OS	FERC NO.175	N/A	N/A	N/A
7	CITY OF HOMESTEAD (2)	OS	FERC NO. 82	N/A	N/A	N/A
8	AMERICAN ELECTRIC POWER CO. (2)	OS	FERC NO. 9	N/A	N/A	N/A
9	GEORGIA POWER (2)	OS	FERC NO. 9	N/A	N/A	N/A
10	GEORGIA TRANSMISSION CORP	OS		N/A	N/A	N/A
11	GEORGIA TRANSMISSION CORP	AD		N/A	N/A	N/A
12	ALABAMA ELECTRIC CO-OP., INC.	OS	FERC NO. 148	N/A	N/A	N/A
13	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 8	N/A	N/A	N/A
14	CAROLINA PWR. & LIGHT CO.	AD	FERC NO. 8	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
11,493			350,000	747,630		1,097,630	1
							2
7,032				394,414		394,414	3
296				13,320		13,320	4
					-42,304	-42,304	5
90,158				4,785,912		4,785,912	6
88				2,502		2,502	7
2,913				85,809		85,809	8
268				18,900		18,900	9
				88,333		88,333	10
					1,845	1,845	11
50				1,400		1,400	12
				-136,051		-136,051	13
					19	19	14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	SO. CAROLINA ELEC. & GAS CO.	OS	FERC NO. 8/10	N/A	N/A	N/A
2	EXELON GENERATION CO., L.L.C.	OS	FERC NO. 10	N/A	N/A	N/A
3	SO. CAROLINA PUB. SVC. AUTHORITY	OS	FERC NO.3/5	N/A	N/A	N/A
4						
5						
6						
7	INADVERTENT INTERCHANGE (NET)					
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,997				364,397		364,397	1
480				32,960		32,960	2
				3,436		3,436	3
							4
							5
							6
-33,684							7
							8
							9
							10
							11
							12
							13
							14
9,362,987			295,680,199	254,418,749	1,601,448	551,700,396	

Schedule Page: 326 Line No.: 1 Column: a

OS (1) - COGENERATION AND SMALL POWER PRODUCERS.

COG - FIRMED AND AS AVAILABLE. COGENERATION CONTRACTS FILED WITH AND APPROVED BY THE FLA. PUBLIC SERVICE COMMISSION.

* - GLADES ELECTRIC COOPERATIVE, INC. IS NOT REGULATED BY FERC OR THE FLA. PUBLIC SERVICE COMMISSION.

Schedule Page: 326 Line No.: 3 Column: c

FPC HAS A FEW RETAIL CUSTOMERS LOCATED CLOSER TO THE GLADES SYSTEM THAN FPC'S SYSTEM. AS A RESULT, IT IS MORE COST EFFECTIVE TO SERVE THESE CUSTOMERS FROM GLADES POWER LINES RATHER THAN FPC LINES. BUT, THE CUSTOMERS REMAIN FPC CUSTOMERS - WITH FPC METERS AND PAYING FPC MONTHLY. HOWEVER, THE POWER THESE CUSTOMERS CONSUME IS FROM THE GLADES SYSTEM AND IS ALSO METERED WITH A GLADES METER. FPC PAYS GLADES FOR THIS POWER EVERY MONTH. THIS MAKES FPC A CUSTOMER OF THE GLADES SYSTEM.

Schedule Page: 326 Line No.: 5 Column: a

OUT OF PERIOD ADJUSTMENT- BAY COUNTY: ($4,745) ENERGY AND $34,430 CAPACITY.

Schedule Page: 326 Line No.: 7 Column: a

OUT OF PERIOD ADJUSTMENT - US AGRI-CHEMICALS: ($28,948) ENERGY AND $5,778 CAPACITY.

Schedule Page: 326 Line No.: 9 Column: a

OUT OF PERIOD ADJUSTMENT - PINELLAS COUNTY: ($24,005) ENERGY AND $284,153 CAPACITY.

Schedule Page: 326 Line No.: 11 Column: a

OUT OF PERIOD ADJUSTMENT - AUBURNDALE: ($10,381) ENERGY AND $284,961 CAPACITY.

Schedule Page: 326 Line No.: 13 Column: a

OUT OF PERIOD ADJUSTMENT - TIMBER ENERGY: ($200,836) CAPACITY.

Schedule Page: 326.1 Line No.: 1 Column: a

OUT OF PERIOD ADJUSTMENT - PASCO COUNTY: ($12,563) ENERGY AND 119,370 CAPACITY.

Schedule Page: 326.1 Line No.: 3 Column: a

OUT OF PERIOD ADJUSTMENT - CARGILL FERTILIZER - $30,948 ENERGY AND $59,850 CAPACITY.

Schedule Page: 326.1 Line No.: 5 Column: a

OUT OF PERIOD ADJUSTMENT-METRO DADE: ($8,334) ENERGY AND $76,559 CAPACITY.

Schedule Page: 326.1 Line No.: 7 Column: a

OUT OF PERIOD ADJUSTMENT - LAKE COGEN: $18,690 ENERGY AND $53,261 CAPACITY.

Schedule Page: 326.1 Line No.: 9 Column: a

OUT OF PERIOD ADJUSTMENT - PASCO COGEN: $241,894 ENERGY AND ($203,008)CAPACITY.

Schedule Page: 326.1 Line No.: 11 Column: a

OUT OF PERIOD ADJUSTMENT - ORLANDO COGEN: ($33,883) ENERGY AND $231,342 CAPACITY.

Schedule Page: 326.1 Line No.: 13 Column: a

OUT OF PERIOD ADJUSTMENT - RIDGE GENERATING STATION: ($17,837) ENERGY AND ($114,495) CAPACITY.

Schedule Page: 326.2 Line No.: 1 Column: a

OUT OF PERIOD ADJUSTMENT-POLK POWER PARTNERS: ($84,995) ENERGY AND ($64,882) CAPACITY.

Schedule Page: 326.2 Line No.: 3 Column: a

OUT OF PERIOD ADJUSTMENT-ORANGE COGEN LIMITED: ($150,131) ENERGY AND $247,704 CAPACITY.

Schedule Page: 326.2 Line No.: 5 Column: a

OUT OF PERIOD ADJUSTMENT - JEFFERSON POWER: $15,238 ENERGY AND ($6,957) CAPACITY.

Schedule Page: 326.2 Line No.: 7 Column: a

OUT OF PERIOD ADJUSTMENT - CITRUS WORLD: ($492) ENERGY.

Schedule Page: 326.2 Line No.: 9 Column: a

OUT OF PERIOD ADJUSTMENT - LAKE COUNTY: ($5,781) ENERGY AND $66,045 CAPACITY.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2003	Dec 31, 2003

FOOTNOTE DATA

Schedule Page: 326.2 Line No.: 11 Column: a

OUT OF PERIOD ADJUSTMENT - PCS PHOSPHATE: ($11,999) ENERGY.

Schedule Page: 326.2 Line No.: 13 Column: a

OS (2) - ECONOMY INTERCHANGE PURCHASES.

OS (3) - ECONOMY AND EMERGENCY INTERCHANGE PURCHASES.

** - AVG. MONTHLY CP DEMAND IS NOT MAINTAINED AS A CORPORATE STATISTIC.

Schedule Page: 326.3 Line No.: 1 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $8,886.00 TO ENERGY CHARGES.

Schedule Page: 326.3 Line No.: 3 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $720,071 TO ENERGY CHARGES.

Schedule Page: 326.3 Line No.: 5 Column: a

OUT-OF-PERIOD ADJUSTMENT OF ($392.00) TO ENERGY CHARGES.

Schedule Page: 326.3 Line No.: 7 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $369.00 TO ENERGY CHARGES.

Schedule Page: 326.3 Line No.: 8 Column: a

TAMPA ELECTRIC CO. RATE SCHEDULE FERC NO. 80. EARLIEST TERMINATION DATE IS 12/31/11.

Schedule Page: 326.3 Line No.: 9 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $119,939 TO ENERGY CHARGES.

Schedule Page: 326.3 Line No.: 12 Column: a

OUT-OF-PERIOD ADJUSTMENT OF ($3.00) TO ENERGY CHARGES.

Schedule Page: 326.4 Line No.: 4 Column: a

OUT-OF-PERIOD ADJUSTMENT OF ($789.00) TO ENERGY CHARGES.

Schedule Page: 326.4 Line No.: 6 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $32.00 TO ENERGY CHARGES.

Schedule Page: 326.4 Line No.: 8 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $7,824.00 TO ENERGY CHARGES.

Schedule Page: 326.5 Line No.: 5 Column: a

CREDIT SCHEDULE H CAPACITY SALES OF ($42,304.00).

Schedule Page: 326.5 Line No.: 11 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $1,845.00 OF CHARGES.

Schedule Page: 326.5 Line No.: 14 Column: a

OUT-OF-PERIOD ADJUSTMENT OF $19.00 TO ENERGY CHARGES.

Schedule Page: 326.6 Line No.: 7 Column: a

INADVERTENT INTERCHANGE IS BEING REPORTED AS A NET TOTAL ADJUSTMENT PER FERC LETTER DATED 05/09/91.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
LF - for Long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Alabama Electric Cooperative	Various	Various	OS
2	American Electric Power Service	Various	Various	OS
3	Florida Municipal Power Agency	Various	Various	LF
4	Florida Power & Light	Progress Energy Florida, Inc	Florida Power & Light	LF
5	Florida Power & Light	Progress Energy Florida, Inc	Florida Power & Light	SF
6	Florida Power & Light	Various	Various	OS
7	City of Homestead	Progress Energy Florida, Inc	City of Homestead	SF
8	CIty of Homestead	Various	City of Homestead	OS
9	City of Homestead	Various	Various	OS
10	Cobb Electric Membership Corporation	Various	Various	OS
11	Constellation Power Source Inc	Various	Various	OS
12	Dynegy Power Marketing, Inc	Various	Various	OS
13	Lakeland Utilities	Various	Various	OS
14	Entergy Koch Trading LP	Various	Various	OS
15	Exelon Generation Company LLC	Various	Various	OS
16	LG&E Energy Marketing	Various	Various	OS
17	Morgan Stanley Capital Group, Inc	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from, designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Tariff No. 6	Various	Various		515	506	1
Tariff No. 6	Various	Various		1,072	1,052	2
Tariff No. 6	Various	Various		480,582	471,847	3
Tariff No. 6	PEF	FL Power & Light	50			4
Tariff No. 6	PEF	FL Power & Light	150			5
Tariff No. 6	Various	Various		3,879	3,801	6
Tariff No. 6	PEF	FL Power & Light	15			7
Tariff No. 6	Various	FL Power & Light				8
Tariff No. 6	Various	Various		87	87	9
Tariff No. 6	Various	Various				10
Tariff No. 6	Various	Various				11
Tariff No. 6	Various	Various				12
Tariff No. 6	Various	Various				13
Tariff No. 6	Various	Various				14
Tariff No. 6	Various	Various				15
Tariff No. 6	Various	Various		1,626	1,593	16
Tariff No. 6	Various	Various				17
			1,058	**1,816,299**	**1,798,457**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		2,178	2,178	1
		2,484	2,484	2
		4,390,160	4,390,160	3
715,800			715,800	4
1,431,600			1,431,600	5
		644,410	644,410	6
35,790			35,790	7
		155,876	155,876	8
		3,207	3,207	9
		5,272	5,272	10
		788	788	11
		16	16	12
		15,195	15,195	13
		11,427	11,427	14
		242	242	15
		78,858	78,858	16
		8	8	17
12,500,868	**-654,047**	**28,298,682**	**40,145,503**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
LF - for Long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Oglethorpe Power Corporation	Various	Various	OS
2	South Carolina Electric & Gas Company	Various	Various	OS
3	Southern Company Services	Various	Various	OS
4	City of New Smyrna Beach	Progress Energy Florida, Inc	City of New Smyrna Beach	LF
5	City of New Smyrna Beach	Various	Various	OS
6	Orlando Utilities Commission	Progress Energy Florida, Inc	Orlando Utilities Commission	OS
7	Orlando Utilities Commission	Various	Various	OS
8	Reedy Creek Improvement District	Various	Various	OS
9	Seminole Elec Cooperative, Inc.	Progress Energy Florida, Inc	Seminole Elec Cooperative, Inc.	OS
10	Seminole Elec Cooperative, Inc.	Various	Various	LF
11	Seminole Elec Cooperative, Inc.	Various	Various	OS
12	Southeastern Power Administration	Project	Preference Customers (18)	LF
13	City of Tallahassee	City of Tallahassee	City of Tallahassee	LF
14	City of Tallahassee	Progress Energy Florida, Inc	City of Tallahassee	OS
15	City of Tallahassee	Various	Various	OS
16	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachual	SF
17	Tampa Electric Company	Progress Energy Florida, Inc	Tampa Electric Company	SF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from, designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Tariff No. 6	Various	Various				1
Tariff No. 6	Various	Various		10,184	9,974	2
Tariff No. 6	Various	Various		297,299	292,668	3
Tariff No.6	Crystal River Sub	New Smyrna Beach	5			4
Tariff No. 6	Various	Various				5
Tariff No. 6	Crystal River Sub	Orlando Utilities Cn	13			6
Tariff No. 6	Various	Various				7
Tariff No. 6	Various	Various		37,517	37,236	8
Tariff No. 6	PEF	Seminole Electric Co	12			9
Tariff No. 6	Various	Various		62,269	61,302	10
Tariff No. 6	Various	Various				11
65	Project	Preference Customers		184,858	197,798	12
Tariff No. 6	Jackson Bluff Sub	City of Tallahassee	11			13
Tariff No. 6	PEF	City of Tallahassee	11			14
Tariff No. 6	Various	Various		63,559	62,811	15
Tariff No. 6	Tampa Electric Co.	Ft. Meade & Wachula	29			16
Tariff No. 6	PEF	Tampa Electric Co.	150			17
			1,058	**1,816,299**	**1,798,457**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		43,174	43,174	1
		10,880	10,880	2
		29,696	29,696	3
56,583			56,583	4
		62,040	62,040	5
161,568			161,568	6
		163,790	163,790	7
		564,098	564,098	8
133,698			133,698	9
		72,755	72,755	10
		19,231,655	19,231,655	11
		266,050	266,050	12
152,261			152,261	13
163,202			163,202	14
		52,976	52,976	15
308,987			308,987	16
715,800			715,800	17
12,500,868	**-654,047**	**28,298,682**	**40,145,503**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
LF - for Long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Tampa Electric Company	Various	Various	OS
2	Orange Cogen L.P.	Orang Cogen L.P.	Tampa Electric Company	OS
3	The Energy Authority	Gainesville Regional Utilities	Gainesville Regional Utilities	OS
4	The Energy Authority	Various	Various	OS
5	FCS-Central Power & Lime	Central Power and Lime	Florida Power and Light	OS
6	FCS - Central Power & Lime	Various	Various	OS
7	Reliant Energy Services	Reliant Energy Services	Florida Power and Light	OS
8	Reliant Energy Services	Various	Various	SF
9	Reliant Energy Services	Various	Various	OS
10	Cargill-Alliant, LLC	Various	Various	OS
11	Cinergy Services Inc	Various	Various	OS
12	City of Alachua	Progress Energy Florida, Inc	City of Alachua	OS
13	City of Kissimmee	Progress Energy Florida, Inc	Kissimmee Utility Authority	LF
14	Duke Energy Trading & Marketing	Various	Various	OS
15	Calpine Energy Services	Various	Various	OS
16	Carolina Power & Light Co	Various	Various	OS
17	Conoco, Inc.	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from, designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff No. 6	Various	Various		26,565	26,427	1
Tariff No. 6	Orange Sub	Tampa Electric Co.	23			2
Tariff No. 6	Archer Sub	Gainesville Regional	2			3
Tariff No. 6	Various	Various				4
Tariff No.6	Brookridge Sub	FL Power & Light	135			5
Tariff No. 6	Various	Various	3			6
Tariff No. 6	Hudson Sub	FL Power & Light	430			7
Tariff No. 6	Various	Various				8
Tariff No. 6	Various	Various				9
Tariff No. 6	Various	Various				10
Tariff No. 6	Various	Various		226	223	11
Tariff No.6	Crystal River Sub	Gainesville Regional	1			12
Tariff No. 6	Crystal River Sub	Kissimmee Utility	6			13
Tariff No. 6	Various	Various		19,863	19,469	14
Tariff No. 6	Various	Various				15
Tariff No. 6	Various	Various		2,479	2,425	16
Tariff No. 6	Various	Various				17
			1,058	**1,816,299**	**1,798,457**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		159,549	159,549	1
318,363			318,363	2
5,488			5,488	3
		451,529	451,529	4
1,874,938			1,874,938	5
42,948			42,948	6
6,155,880	-654,047		5,501,833	7
9,920			9,920	8
		395,982	395,982	9
		427,117	427,117	10
		18,462	18,462	11
7,864			7,864	12
68,141			68,141	13
		35,310	35,310	14
		10,700	10,700	15
		37,404	37,404	16
		22,001	22,001	17
12,500,868	**-654,047**	**28,298,682**	**40,145,503**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Gainesville Regional Utilities	Progress Energy Florida, Inc	Gainesville Regional Utilities	OS
2	Tennessee Valley Authority	Various	Various	OS
3	Virginia Electric Company	Various	Various	OS
4	Georgia Power	Various	Various	OS
5	Associated Electric Company	Various	Various	OS
6	Ameren Energy	Various	Various	OS
7	Auburndale Power Partners	Various	Various	OS
8	Commonwealth Edison	Various	Various	OS
9	Central Louisiana Electric Company	Various	Various	OS
10	Dayton Power & Light	Various	Various	OS
11	Entergy Electric System	Various	Various	OS
12	East Kentucky Power Cooperative	Various	Various	OS
13	Indianapolis Power and Light	Various	Various	OS
14	Jacksonville Electric Authority	Various	Various	OS
15	Nebraska Power District	Various	Various	OS
16	Louisiana Generating LLC	Various	Various	OS
17	Crystal River No. 3 Participants	Progress Energy Florida, Inc	Various	LF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from, designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.
AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff No. 6	Crystal River Sub	Gainesville Regional	12	37,567	37,043	1
Tariff No. 6	Various	Various				2
Tariff No. 6	Various	Various				3
Tariff No. 6	Various	Various				4
Tariff No. 6	Various	Various		2,583	2,530	5
Tariff No. 6	Various	Various		521	513	6
Tariff No. 6	Various	Various		300	300	7
Tariff No. 6	Various	Various		198	194	8
Tariff No. 6	Various	Various		51	50	9
Tariff No. 6	Various	Various		99	96	10
Tariff No. 6	Various	Various		1,593	1,563	11
Tariff No. 6	Various	Various		40	39	12
Tariff No. 6	Various	Various		2,142	2,101	13
Tariff No. 6	Various	Various		36,005	35,318	14
Tariff No. 6	Various	Various		1,104	1,080	15
Tariff No. 6	Various	Various		726	718	16
Tariff No. 6	Various	Various		540,790	527,693	17
			1,058	**1,816,299**	**1,798,457**	

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
142,037			142,037	1
		33,271	33,271	2
		122	122	3
		900,000	900,000	4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
12,500,868	**-654,047**	**28,298,682**	**40,145,503**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 2 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 3 Column: d
Long-Term contract classification remains in effect for life unless terminated by either party with written notice.

Schedule Page: 328 Line No.: 4 Column: d
Long-Term contract classification remains in effect for life unless terminated by either party with written notice.

Schedule Page: 328 Line No.: 4 Column: f
Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328 Line No.: 5 Column: f
Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328 Line No.: 6 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 7 Column: f
Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328 Line No.: 8 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 9 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 10 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 11 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 12 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 13 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 14 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 15 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 16 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328 Line No.: 17 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 1 Column: d
Other Service contract classification is for contracts with a term of less than one year.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 2 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 3 Column: d

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Schedule Page: 328.1 Line No.: 4 Column: d

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Schedule Page: 328.1 Line No.: 5 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 6 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 7 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 8 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 9 Column: d

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Schedule Page: 328.1 Line No.: 9 Column: f

Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328.1 Line No.: 10 Column: d

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Schedule Page: 328.1 Line No.: 11 Column: d

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Schedule Page: 328.1 Line No.: 12 Column: d

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Schedule Page: 328.1 Line No.: 13 Column: d

Long-Term contract classification remains in effect for life unless terminated by either party with written notice.

Schedule Page: 328.1 Line No.: 14 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 14 Column: f

Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328.1 Line No.: 15 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.1 Line No.: 17 Column: f

Florida Power Corporation doing business as Progress Energy Florida, Inc is abbreviated as PEF.

Schedule Page: 328.2 Line No.: 1 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 2 Column: d

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FOOTNOTE DATA

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 3 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 4 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 5 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 6 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 7 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 9 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 10 Column: d

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Schedule Page: 328.2 Line No.: 11 Column: d

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Schedule Page: 328.2 Line No.: 12 Column: d

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Schedule Page: 328.2 Line No.: 14 Column: d

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Schedule Page: 328.2 Line No.: 15 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 16 Column: a

Carolina Power and Light is an affliate of Florida Power Corporation.

Schedule Page: 328.2 Line No.: 16 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.2 Line No.: 17 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.3 Line No.: 1 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.3 Line No.: 2 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.3 Line No.: 3 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.3 Line No.: 4 Column: d

Other Service contract classification is for contracts with a term of less than one year.

Schedule Page: 328.3 Line No.: 5 Column: d
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	436,502
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-26,057
6	Inventory reserve	2,426,500
7	Accounting adjustments	1,937,959
8	Lease exit costs	937,209
9	Service Company allocations	851,338
10	Labor accruals	413,564
11		
12		
13		
14		
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45		
46	TOTAL	6,977,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			16,870,776		16,870,776
2	Steam Production Plant	49,897,572				49,897,572
3	Nuclear Production Plant	30,832,207	1,491,608			32,323,815
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	33,878,274		180,113		34,058,387
7	Transmission Plant	22,655,770				22,655,770
8	Distribution Plant	100,216,102				100,216,102
9	General Plant	5,796,564		111,336		5,907,900
10	Common Plant-Electric					
11	TOTAL	243,276,489	1,491,608	17,162,225		261,930,322

B. Basis for Amortization Charges

Account 404

Subaccount 370.1 - Meters (Energy Conservation)
Subaccount 398.1 - Miscellaneous Equipment (Energy Conservation)
ASL = 5 Years NSR = 0%
Accrual Rate = 20%

Account 405

Subaccount 303 - Intangible Plant
ASL = 5 Years NSR = 0%
Accrual Rate = 20%

Subaccount 303.1 - Intangible Plant - CSS

ASL = 10 Years NSR = 0%
Accrual Rate = 10%

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	See Footnote						
13							
14							
15							
16							
17							
18							
19							
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48							
49							
50							

Schedule Page: 336 Line No.: 12 Column: a

Per Instruction #3 for Section C, page 336 - All available information was adequately reported during the FERC Form 1 submission of 2001. Therefore, only accounts with changes to Estimated Avg Life, Net Salvage (Percent), Applied Depreciation Rates (Percent), Mortality Curve Type or Average Remaining Life would be listed.

No accounts appear to have changes that would warrant listing in the 2003 FERC Form 1 submission.

Per Florida Public Service Commission Docket No. 020001-EI, Order No. PSC-02-0655-AS-EI, issued May 14, 2002, the Florida Public Service Commission approved a settlement which allowed Florida Power Corporation to reduce depreciation expense annually by $62.5M. This reduction is reflected in the totals in Part A column b.

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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	55,646,648		
4	Transmission	9,308,508		
5	Distribution	28,347,449		
6	Customer Accounts	20,857,641		
7	Customer Service and Informational	9,416,495		
8	Sales	1,285,408		
9	Administrative and General	45,422,815		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	170,284,964		
11	Maintenance			
12	Production	35,104,771		
13	Transmission	2,019,601		
14	Distribution	3,788,299		
15	Administrative and General	2,751,122		
16	TOTAL Maint. (Total of lines 12 thru 15)	43,663,793		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	90,751,419		
19	Transmission (Enter Total of lines 4 and 13)	11,328,109		
20	Distribution (Enter Total of lines 5 and 14)	32,135,748		
21	Customer Accounts (Transcribe from line 6)	20,857,641		
22	Customer Service and Informational (Transcribe from line 7)	9,416,495		
23	Sales (Transcribe from line 8)	1,285,408		
24	Administrative and General (Enter Total of lines 9 and 15)	48,173,937		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	213,948,757	17,581,305	231,530,062
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Enter Total of lines 28 thru 37)			
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	213,948,757	17,581,305	231,530,062
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	96,774,682		96,774,682
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	96,774,682		96,774,682
69	Plant Removal (By Utility Departments)			
70	Electric Plant			
71	Gas Plant			
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)			
74	Other Accounts (Specify, provide details in footnote):			
75	Stores Expense Undistributed	5,533,074	505,191	6,038,265
76	Clearing Accounts	9,089,988	347,007	9,436,995
77	Miscellaneous Deferred Debits	1,349,321		1,349,321
78	All Other Accounts	6,016,786	126,539	6,143,325
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	21,989,169	978,737	22,967,906
96	TOTAL SALARIES AND WAGES	332,712,608	18,560,042	351,272,650

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	22,979,312
4	Nuclear	6,038,641
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	6,475,512
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	35,493,465
10	Purchases	9,362,987
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	1,816,299
17	Delivered	1,798,457
18	Net Transmission for Other (Line 16 minus line 17)	17,842
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	44,874,294

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	37,956,702
23	Requirements Sales for Resale (See instruction 4, page 311.)	3,359,432
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	963,184
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	118,565
27	Total Energy Losses	2,476,411
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	44,874,294

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

MONTHLY PEAKS AND OUTPUT

1. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report in column (b) the system's energy output for each month such that the total on Line 41 matches the total on Line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on Line 24. include in the monthly amounts any energy losses associated with the sales so that the total on Line 41 exceeds the amount on Line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt Load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c)
5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	3,979,669	138,027	10,131	24	7-8 A.M.
30	February	3,055,056	240,654	6,142	12	7-8 A.M.
31	March	3,388,744	150,001	6,658	20	2-3 P.M.
32	April	3,284,326	94,377	6,690	7	5-6 P.M.
33	May	4,040,133	24,344	7,665	12	4-5 P.M.
34	June	4,020,290	4,543	7,914	11	4-5 P.M.
35	July	4,367,474	16,524	8,105	9	2-3 P.M.
36	August	4,231,168	10,767	7,882	13	8-9 A.M.
37	September	4,007,211	19,266	7,610	24	8-9 A.M.
38	October	3,640,781	9,321	7,021	13	4-5 P.M.
39	November	3,298,168	97,395	6,519	5	1-2 P.M.
40	December	3,561,274	157,965	7,801	21	8-9 A.M.
41	TOTAL	44,874,294	963,184			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Anclote* (b)			Plant Name: *Bartow* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1974			1958		
4	Year Last Unit was Installed	1978			1963		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1112.40			494.40		
6	Net Peak Demand on Plant - MW (60 minutes)	1019			448		
7	Plant Hours Connected to Load	15500			23284		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1044			452		
10	When Limited by Condenser Water	993			444		
11	Average Number of Employees	79			83		
12	Net Generation, Exclusive of Plant Use - KWh	4023169000			2314037000		
13	Cost of Plant: Land and Land Rights	1869309			2046939		
14	Structures and Improvements	35902465			19078868		
15	Equipment Costs	226564528			123798283		
16	Asset Retirement Costs	0			0		
17	Total Cost	264336302			144924090		
18	Cost per KW of Installed Capacity (line 17/5) Including	237.6270			293.1313		
19	Production Expenses: Oper, Supv, & Engr	946			81221		
20	Fuel	175756816			95215372		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	352672			390151		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	5560769			3779418		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1423553			893178		
30	Maintenance of Structures	699604			125669		
31	Maintenance of Boiler (or reactor) Plant	2183817			754107		
32	Maintenance of Electric Plant	2517531			599794		
33	Maintenance of Misc Steam (or Nuclear) Plant	5823243			3493433		
34	Total Production Expenses	194318951			105332343		
35	Expenses per Net KWh	0.0483			0.0455		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL	MCF	
38	Quantity (Units) of Fuel Burned	6105560	713581	0	3680704	4	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	157036	1038	0	156316	1000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	29.673	6.858	0.000	25.672	5.500	0.000
41	Average Cost of Fuel per Unit Burned	27.676	6.858	0.000	25.454	5.518	0.000
42	Average Cost of Fuel Burned per Million BTU	4.196	6.610	0.000	3.877	5.518	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.067	0.000	0.055	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10198.000	0.000	14281.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Crystal River South* (d)			Plant Name: *Crystal River North* (e)			Plant Name: *Crystal River* (f)			Line No.
		Steam			Steam			Nuclear	1
		Conventional			Conventional			Conventional	2
		1966			1982			1977	3
		1969			1984			1977	4
		964.40			1478.50			890.50	5
		870			1452			779	6
		15539			17180			7912	7
		0			0			0	8
		874			1467			788	9
		865			1437			769	10
		164			150			497	11
		5344040000			10832929000			6038641000	12
		2512007			0			41218	13
		74437609			148933350			244386465	14
		318713843			750669246			592340033	15
		0			0			77064813	16
		395663459			899602596			913832529	17
		410.2690			608.4563			1026.2016	18
		618612			769852			136291	19
		119992843			260275513			31099846	20
		0			0			2872185	21
		2286345			4214911			10832476	22
		0			0			0	23
		0			0			0	24
		262			0			0	25
		5115820			5623840			30564003	26
		0			0			0	27
		0			0			0	28
		335998			460547			7442687	29
		379547			195430			7179095	30
		712802			1033910			11799427	31
		1607806			341567			3425070	32
		10047277			7433069			2288427	33
		141097312			280348639			107639507	34
		0.0264			0.0259			0.0178	35
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
27164	2093606	0	81383	4106741	0	278	61900670	0	38
137463	12613	0	137081	12442	0	134464	0	0	39
39.012	56.072	0.000	38.803	61.385	0.000	47.835	0.000	0.000	40
38.428	55.340	0.000	39.146	61.043	0.000	47.835	0.356	0.000	41
6.656	2.194	0.000	6.799	2.453	0.000	8.470	0.448	0.000	42
0.066	0.000	0.000	0.064	0.000	0.000	0.000	0.005	0.000	43
9903.000	0.000	0.000	9477.000	0.000	0.000	0.000	10251.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Suwannee* (b)			Plant Name: *Bayboro* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1953			1973
4	Year Last Unit was Installed			1956			1973
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			147.00			226.80
6	Net Peak Demand on Plant - MW (60 minutes)			145			208
7	Plant Hours Connected to Load			14276			995
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			146			232
10	When Limited by Condenser Water			143			184
11	Average Number of Employees			36			5
12	Net Generation, Exclusive of Plant Use - KWh			465137000			36320000
13	Cost of Plant: Land and Land Rights			22059			1597635
14	Structures and Improvements			4784696			1428456
15	Equipment Costs			27649895			20151974
16	Asset Retirement Costs			0			0
17	Total Cost			32456650			23178065
18	Cost per KW of Installed Capacity (line 17/5) Including			220.7935			102.1961
19	Production Expenses: Oper, Supv, & Engr			4754			199816
20	Fuel			27145446			3136229
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			335009			132535
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			2085854			361362
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			34714			0
30	Maintenance of Structures			36565			2703
31	Maintenance of Boiler (or reactor) Plant			36705			0
32	Maintenance of Electric Plant			27283			104395
33	Maintenance of Misc Steam (or Nuclear) Plant			1285999			-18140
34	Total Production Expenses			30992329			3918900
35	Expenses per Net KWh			0.0666			0.1079
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL		
38	Quantity (Units) of Fuel Burned	839977	116506	0	86044	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	157272	1033	0	138678	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	30.099	6.376	0.000	36.950	0.000	0.000
41	Average Cost of Fuel per Unit Burned	30.746	6.376	0.000	35.870	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.655	6.173	0.000	6.159	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.070	0.000	0.085	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	11260.000	0.000	13798.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Debary* (d)			Plant Name: *Intercession City* (e)			Plant Name: *Suwannee* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbines			1
Conventional			Conventional			Conventional			2
1975			1974			1980			3
1992			1992			1980			4
861.40			1310.20			183.60			5
715			1124			183			6
10223			14363			1938			7
0			0			0			8
762			1206			201			9
667			1041			164			10
20			21			2			11
492989000			774758000			77119000			12
2113330			746305			0			13
9181448			21963362			1471199			14
137832019			224623596			27199608			15
0			0			0			16
149126797			247333263			28670807			17
173.1214			188.7752			156.1591			18
1443190			1651916			339395			19
42501866			69189462			7243932			20
0			0			0			21
166116			163681			24381			22
0			0			0			23
0			0			0			24
0			0			0			25
987349			1509199			220743			26
0			0			0			27
0			0			0			28
9226			428643			0			29
95403			38342			10727			30
0			0			0			31
11577			239058			532077			32
1858906			4049046			1042339			33
47073633			77269347			9413594			34
0.0955			0.0997			0.1221			35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
318309	4674875	0	338295	8022432	0	68275	652222	0	38
138312	1046	0	138180	1044	0	138896	1033	0	39
38.480	6.551	0.000	38.695	7.091	0.000	37.307	7.117	0.000	40
36.824	6.551	0.000	35.082	7.091	0.000	35.856	7.117	0.000	41
6.339	6.265	0.000	6.045	6.790	0.000	6.146	6.892	0.000	42
0.087	0.000	0.000	0.000	0.091	0.000	0.000	0.096	0.000	43
13666.000	0.000	0.000	0.000	13348.000	0.000	0.000	13897.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Bartow* (b)			Plant Name: *Turner* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbines			Gas Turbines		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1972			1970		
4	Year Last Unit was Installed	1972			1974		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	222.80			181.00		
6	Net Peak Demand on Plant - MW. (60 minutes)	203			174		
7	Plant Hours Connected to Load	2206			454		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	219			194		
10	When Limited by Condenser Water	187			154		
11	Average Number of Employees	6			0		
12	Net Generation, Exclusive of Plant Use - KWh	64604000			21070000		
13	Cost of Plant: Land and Land Rights	0			824781		
14	Structures and Improvements	1074388			952405		
15	Equipment Costs	22947108			21367172		
16	Asset Retirement Costs	0			0		
17	Total Cost	24021496			23144358		
18	Cost per KW of Installed Capacity (line 17/5) Including	107.8164			127.8694		
19	Production Expenses: Oper, Supv, & Engr	626355			325411		
20	Fuel	7226405			2281066		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	39162			19268		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	317323			189061		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1111			0		
30	Maintenance of Structures	1568			15126		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	46737			9024		
33	Maintenance of Misc Steam (or Nuclear) Plant	564001			283530		
34	Total Production Expenses	8822662			3122486		
35	Expenses per Net KWh	0.1366			0.1482		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL		
38	Quantity (Units) of Fuel Burned	31502	908057	0	53708	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138563	1043	0	138142	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	39.127	6.405	0.000	39.499	0.000	0.000
41	Average Cost of Fuel per Unit Burned	35.806	6.405	0.000	36.473	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	6.153	6.139	0.000	6.286	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.108	0.000	0.000	0.093	0.000	0.000
44	Average BTU per KWh Net Generation	17502.000	0.000	0.000	14789.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Avon Park* (d)			Plant Name: *Higgins* (e)			Plant Name: *Tiger Bay* (f)			Line No.
		Gas Turbines			Gas Turbines			Gas Turbines	1
		Conventional			Conventional			Conventional	2
		1968			1969			1995	3
		1968			1971			1995	4
		67.60			153.40			278.20	5
		58			128			215	6
		655			1328			7566	7
		0			0			0	8
		64			134			223	9
		52			122			207	10
		0			0			2	11
		15307000			32771000			1425739000	12
		67207			184271			0	13
		429406			706189			4610421	14
		8136731			16066927			83772244	15
		0			0			0	16
		8633344			16957387			88382665	17
		127.7122			110.5436			317.6947	18
		396949			56413			1809951	19
		1631420			3222311			40718266	20
		0			0			0	21
		9406			197870			40042	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		108807			165551			540577	26
		0			0			0	27
		0			0			0	28
		1797			0			253713	29
		375			10904			8950	30
		0			0			0	31
		9856			384467			0	32
		364204			165313			3270546	33
		2522814			4202829			46642045	34
		0.1648			0.1282			0.0327	35
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
15378	161992	0	808	553441	0	10600842	0	0	38
138409	1042	0	137376	1041	0	1043	0	0	39
40.651	6.263	0.000	38.195	5.704	0.000	3.841	0.000	0.000	40
38.661	6.263	0.000	34.697	5.704	0.000	3.841	0.000	0.000	41
6.651	6.008	0.000	6.014	5.479	0.000	3.683	0.000	0.000	42
0.112	0.000	0.000	0.107	0.000	0.000	0.029	0.000	0.000	43
16872.000	0.000	0.000	17724.000	0.000	0.000	7754.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Rio Pinar* (b)			Plant Name: *Univ.of Florida* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbines			Gas Turbines		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			1994		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	19.30			43.00		
6	Net Peak Demand on Plant - MW (60 minutes)	15			38		
7	Plant Hours Connected to Load	247			7671		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	16			41		
10	When Limited by Condenser Water	13			35		
11	Average Number of Employees	0			11		
12	Net Generation, Exclusive of Plant Use - KWh	2968000			345867000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	71472			6395328		
15	Equipment Costs	3010599			34403661		
16	Asset Retirement Costs	0			0		
17	Total Cost	3082071			40798989		
18	Cost per KW of Installed Capacity (line 17/5) Including	159.6928			948.8137		
19	Production Expenses: Oper, Supv, & Engr	26734			584537		
20	Fuel	329684			18468808		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	14768			37983		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	21315			232469		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			3678		
30	Maintenance of Structures	28970			194823		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			565900		
33	Maintenance of Misc Steam (or Nuclear) Plant	29504			1024874		
34	Total Production Expenses	450975			21113072		
35	Expenses per Net KWh	0.1519			0.0610		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil			Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL			BBL	MCF	
38	Quantity (Units) of Fuel Burned	8743	0	0	0	3484009	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138140	0	0	0	1043	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	37.205	0.000	0.000	0.000	5.267	0.000
41	Average Cost of Fuel per Unit Burned	36.569	0.000	0.000	0.000	5.267	0.000
42	Average Cost of Fuel Burned per Million BTU	6.303	0.000	0.000	0.000	5.048	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.108	0.000	0.000	0.000	0.053	0.000
44	Average BTU per KWh Net Generation	17091.000	0.000	0.000	0.000	10510.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Hines Energy Complex* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas Turbines			1
Conventional			2
1999			3
2003			4
1144.60	0.00	0.00	5
1055	0	0	6
9957	0	0	7
0	0	0	8
1111	0	0	9
998	0	0	10
38	0	0	11
3186000000	0	0	12
13112538	0	0	13
28462292	0	0	14
492546983	0	0	15
0	0	0	16
534121813	0	0	17
466.6450	0.0000	0.0000	18
4755	0	0	19
162472795	0	0	20
0	0	0	21
2793267	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
866124	0	0	26
0	0	0	27
0	0	0	28
329641	0	0	29
0	0	0	30
0	0	0	31
1921	0	0	32
3922743	0	0	33
170391246	0	0	34
0.0535	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Oil	Gas								36
BBL	MCF								37
31927	22643980	0	0	0	0	0	0	0	38
133007	1043	0	0	0	0	0	0	0	39
47.024	7.210	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
27.811	7.210	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
4.978	6.916	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.052	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	7466.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	500KV LINES	OVERHEAD						
2	CENTRAL FLORIDA	KATHLEEN	500.00	500.00	ST	44.22		1
3	CRYSTAL RIVER SUB	BROOKRIDGE	500.00	500.00	ST	34.40		1
4	BROOKRIDGE	LAKE TARPON	500.00	500.00	ST	37.63		1
5	CRYSTAL RIVER SUB	CENTRAL FLORIDA	500.00	500.00	ST	52.91		1
6								
7	230 KV LINES	UNDERGROUND						
8	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.91		1
9	BARTOW PLANT	NORTHEAST	230.00	230.00	HPOF	3.98		1
10								
11	230 KV LINES	OVERHEAD						
12	CENTRAL FLORIDA	CFO 72	69.00	230.00	WP	0.28		1
13					ST		18.28	1
14	FX 24	FX 68	69.00	230.00	ST		4.17	1
15	PT ST JOE	ST JOE IND	69.00	230.00	ST		1.43	1
16	PS 130	SES 4	69.00	230.00	SP		1.01	1
17	CFO 87	CFO 72 1/2	69.00	230.00	ST		3.77	1
18	WINDERMERE	WIC 7	69.00	230.00	CP		0.88	1
19	WINDERMERE	WXO 9	69.00	230.00	WH		1.07	1
20	AVON PARK	AF 44	115.00	230.00	ST		4.30	1
21	AVON PARK	FORT MEADE	230.00	230.00	ST	4.30		1
22					CP	2.01		
23					WH	19.86		
24					WP	0.94		
25					SP		1.22	
26	AVON PARK	FISHEATING CREEK	230.00	230.00	SP	9.02		1
27					CP	17.05		
28					WH	3.29		
29	ANCLOTE PLANT	LARGO	230.00	230.00	SH	15.29		1
30					SP	8.54		
31	ANCLOTE PLANT	EAST CLEARWATER	230.00	230.00	SH		15.30	1
32	ANCLOTE PLANT	SEVEN SPRINGS	230.00	230.00	SP	7.71		1
33	ALTAMONTE	WOODSMERE	230.00	230.00	WP	0.10		1
34					ST		0.56	
35					WH	10.20		
36					TOTAL	3,979.96	446.63	81

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,099,487	20,117,954	22,217,441					2
2335 KCM ACSR	12,767	12,202,249	12,215,016					3
2335 KCM ACSR								4
2335 KCM ACSR	9,840	8,756,291	8,766,131					5
								6
								7
2500 KCM CU		2,088,494	2,088,494					8
2500 KCM CU	251,470	2,109,689	2,361,159					9
								10
								11
795 KCM AAC		93,899	93,899					12
1590 KCM ACSR								13
795 KCM AAC		380,735	380,735					14
795 KCM ACSR	11,479	56,836	68,315					15
795 KCM ACSR	40,406	1,080,009	1,120,415					16
1590 KCM ACSR		258,006	258,006					17
954 KCM ACSR	272,999	1,513,006	1,786,005					18
954 KCM ACSR	269,521	3,653,235	3,922,756					19
4/0 CU	303,961	2,371,449	2,675,410					20
1081 KCM ACSR	85,476	3,416,959	3,502,435					21
954 KCM ACSR								22
954 KCM ACSR								23
954 KCM ACSR								24
954 KCM ACSR								25
1590 KCM ACSR	481,954	8,826,523	9,308,477					26
1590 KCM ACSR								27
1590 KCM ACSR								28
1590 KCM ACSR	389,829	5,616,793	6,006,622					29
1590 KCM ACSR								30
1590 KCM ACSR		635,748	635,748					31
2335 KCM ACAR	1,145,863	1,387,207	2,533,070					32
1590 KCM ACSR	43,803	1,550,285	1,594,088					33
1590 KCM ACSR								34
1590 KCM ACSR								35
	41,848,845	495,022,374	536,871,219	52,708	8,580,863		8,633,571	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION LINE STATISTICS

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1					SP	0.82		
2	BARCOLA	LAKELAND WEST	230.00	230.00	WH	18.68		1
3	BARCOLA	PEBBLEDALE	230.00	230.00	CP	3.86		1
4	BROOKRIDGE	BROOKRIDGE	230.00	230.00	WP	0.21		1
5	CRYSTAL RIVER	CURLEW	230.00	230.00	ST	77.82	72.50	1
6	CRYSTAL RIVER	ANDERSON	230.00	230.00	ST	53.36	39.59	1
7	CRYSTAL RIVER	FT. WHITE	230.00	230.00	WH	73.31		1
8	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	27.49	5.51	1
9					CP	0.69		
10	CFS 1	SORRENTO	230.00	230.00	CP	14.65		1
11					SP	14.82		
12	CENTRAL FLORIDA	WINDERMERE	230.00	230.00	ST	46.61	46.61	1
13	CRAWFORDVILLE	PERRY	230.00	230.00	ST	12.09		1
14					WH	40.35		
15	CRAWFORDVILLE	PORT ST. JOE	230.00	230.00	WH	58.85		1
16					SP	2.65		
17					SH	0.65		
18	CC-248	SEVEN SPRINGS	230.00	230.00	ST		2.90	1
19	DEBARY	ALTAMONTE	230.00	230.00	SP	3.40	8.59	1
20					WH	3.06		
21					ST	0.63	3.36	
22					CP	0.49	0.42	
23	DEBARY	DELAND WEST	230.00	230.00	WH	7.15		1
24					WP	1.94		
25					CP	1.13		
26	DEBARY	NORTH LONGWOOD	230.00	230.00	WH	1.32		1
27					CH		0.54	
28					ST	3.36		
29					CP	0.42		
30					SP	9.15		
31	DEARMAN	SILVER SPRINGS	230.00	230.00	CP	4.27		1
32					ST		1.21	
33	DEBARY	WINTER SPRINGS	230.00	230.00	WH	3.23		1
34					SP	16.78		
35					ST	0.58		
36					TOTAL	3,979.96	446.63	81

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TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR								1
1590 KCM ACSR	133,007	2,576,890	2,709,897					2
1622 KCM		3,427,956	3,427,956					3
1590 KCM ACSR		110,272	110,272					4
1590 KCM ACSR	1,266,890	10,762,869	12,029,759					5
1590 KCM ACSR	774,675	6,750,321	7,524,996					6
954 KCM ACSR	219,431	5,397,859	5,617,290					7
1590 KCM ACSR	439,516	3,220,391	3,659,907					8
1590 KCM ACSR								9
1590 KCM ACSR	1,621,137	10,713,298	12,334,435					10
1590 KCM ACSR								11
1590 KCM ACSR	1,128,343	5,903,286	7,031,629					12
954 KCM ACSR	439,029	4,537,970	4,976,999					13
954 KCM ACSR								14
954 KCM ACSR	176,825	5,706,281	5,883,106					15
954 KCM ACSR								16
954 KCM ACSR								17
1590 KCM ACSR	66,391	139,498	205,889					18
1590 KCM ACSR	271,527	2,250,763	2,522,290					19
1590 KCM ACSR								20
1590 KCM ACSR								21
1590/1431 KCM								22
1590 KCM ACSR	557,537	2,493,378	3,050,915					23
1590 KCM ACSR								24
1590 KCM ACSR								25
954 KCM ACSR	129,493	2,918,991	3,048,484					26
954 KCM ACSR								27
1590 KCM ACSR								28
1431 KCM ACSR								29
1590 KCM ACSR								30
954 KCM ACSR	195,181	1,614,155	1,809,336					31
954 KCM ACSR								32
1590 KCM ACSR	1,073,673	10,865,156	11,938,829					33
1590 KCM ACSR								34
1590 KCM ACSR								35
	41,848,845	495,022,374	536,871,219	52,708	8,580,863		8,633,571	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION LINE STATISTICS

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	FORT WHITE	SILVER SPRINGS	230.00	230.00	ST	1.46		1
2					SL	4.99		
3					CH	64.80		
4					CP	3.21		
5	FSP 1	PASADENA	230.00	230.00	CP	0.20		1
6					SP	3.66		
7	FORT MEADE	VANDOLAH	230.00	230.00	SP	1.20		1
8					WH	21.05		
9					CP	1.80		
10	FORT MEADE	WEST LAKE WALES	230.00	230.00	ST	3.07		1
11					WH	16.80		
12	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
13					ST	5.86		
14					WH	1.28		
15	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.45		1
16	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
17	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
18	HINES ENERGY	TIGER BAY	230.00	230.00	SP	2.25		
19	HINES PLANT	HINES	230.00	230.00	SP	1.64		
20	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
21	KATHLEEN	LAKELAND	230.00	230.00	WH	14.50		1
22					CP	1.31		
23	KATHLEEN	ZEPHYRHILLS	230.00	230.00	WH	0.83		1
24					CP	8.70		
25					WP	1.35		
26	LARGO	PASADENA	230.00	230.00	ST		1.61	1
27					SP	13.13		
28	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
29	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
30					SP	3.02		
31	CURLEW	CLEARWATER	230.00	230.00	SP	14.49		1
32					CP	2.90		
33	CC 248	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
34	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
35					SP	0.81		
36					TOTAL	3,979.96	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 KCM ACSR	449,980	4,431,032	4,881,012					1
795 KCM ACSR								2
795 KCM ACSR								3
954 KCM ACSR								4
1590 KCM ACSR	2,510	858,026	860,536					5
1590 KCM ACSR								6
954 KCM ACSR	63,923	3,216,807	3,280,730					7
954 KCM ACSR								8
954 KCM ACSR								9
1081 KCM ACAR	55,284	1,294,309	1,349,593					10
1081 KCM ACAR								11
1590/1081 KCM	2,353	378,382	380,735					12
1081 KCM ACAR								13
1081/954 KCM								14
954 KCM ACSR		2,805,003	2,805,003					15
954 KCM ACSR		1,531,577	1,531,577					16
954 KCM ACSR		1,412,301	1,412,301					17
954 KCM ACSR		1,455,041	1,455,041					18
954 KCM ACSR		182,380	182,380					19
2335 KCM ACAR		194,088	194,088					20
1590 KCM ACSR	485,915	2,921,127	3,407,042					21
1590 KCM ACSR								22
1590 KCM ACSR	275,097	3,010,806	3,285,903					23
1590 KCM ACSR								24
1590 KCM ACSR								25
1590 KCM ACSR	152,473	2,700,828	2,853,301					26
1590 KCM ACSR								27
1590 KCM ACSR		955,417	955,417					28
1590 KCM ACSR	15,699	1,499,798	1,515,497					29
1590 KCM ACSR								30
1590 KCM ACSR	412,563	8,575,830	8,988,393					31
1590 KCM ACSR								32
1590 KCM ACSR	189,338	694,404	883,742					33
1590 KCM ACSR		197,855	197,855					34
1590 KCM ACSR								35
	41,848,845	495,022,374	536,871,219	52,708	8,580,863		8,633,571	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	NORTHEAST	CUR CC 301	230.00	230.00	ST	16.95	12.78	1
2	NORTHEAST	FSP 1	230.00	230.00	CP	0.16		1
3					SP	8.16		
4	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
5					WH	6.16		
6	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
7					WH	2.77		
8	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
9					CP	0.21		
10					AT	10.91		
11	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
12	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
13	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
14					CP	6.45		
15					WH	4.79		
16	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
17	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
18	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
19					AT	2.19		
20	CFO 89	DELAND WEST	230.00	230.00	SL	39.93		1
21					SH	0.92		
22					SP	1.57		
23	SUWANNEE	FORT WHITE	230.00	230.00	ST	38.08		1
24	SLX 1	OUC SO WD	230.00	230.00	CP	2.40		1
25					WP	2.22		
26	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
27	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
28	SUWANNEE	GEORGIA	230.00	230.00	ST	18.36		1
29	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
30	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
31	WINDERMERE	INTERCESSION CITY	230.00	230.00	WH	9.80		1
32					CP	0.27		
33					SP	5.33	4.85	
34	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
35					ST	1.82		
36					TOTAL	3,979.96	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR	1,517,258	2,482,574	3,999,832					1
1590 KCM ACSR	288,076	1,369,702	1,657,778					2
1081 KCM ACAR								3
954 KCM ACSR	16,834	512,535	529,369					4
954 KCM ACSR								5
954 KCM ACSR	207,841	1,123,050	1,330,891					6
954 KCM ACSR								7
1590 KCM ACSR	420,736	1,976,421	2,397,157					8
954 KCM ACSR								9
954 KCM ACSR								10
1590 KCM ACSR	661,118	5,775,605	6,436,723					11
954 KCM ACSR		4,498	4,498					12
1590 KCM ACSR	574,273	4,917,855	5,492,128					13
1590 KCM ACSR								14
1590 KCM ACSR								15
954 KCM ACSR	15,605	491,284	506,889					16
795 KCM ACSR	71,747	2,297,172	2,368,919					17
954 KCM ACSR	100,034	704,855	804,889					18
954 KCM ACSR								19
1590 KCM ACSR	54,890	6,226,547	6,281,437					20
1590 KCM ACSR								21
1590 KCM ACSR								22
954 KCM ACSR	196,750	2,362,830	2,559,580					23
954 KCM ACSR	121,530	1,160,369	1,281,899					24
954 KCM ACSR								25
795 KCM ACSR	151,754	1,320,102	1,471,856					26
795 KCM ACSR		8,063	8,063					27
954 KCM ACSR	104,190	1,110,240	1,214,430					28
954 KCM ACSR		747,871	747,871					29
1590 KCM ACSR	601,048	578,997	1,180,045					30
954 KCM ACSR	135,968	2,654,588	2,790,556					31
954 KCM								32
1622ACSS TW								33
1590 KCM ACSR	19,739	876,994	896,733					34
1590 KCM ACSR								35
	41,848,845	495,022,374	536,871,219	52,708	8,580,863		8,633,571	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH	29.34		1
2					SP	0.65		
3	WEST LAKE WALES	FP&L CO	230.00	230.00	AT	58.48		1
4	WEST LAKE WALES	TECO	230.00	230.00	AT	2.29		1
5	WOODSMERE	WIW 45	230.00	230.00	ST		0.92	1
6	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
7								
8								
9								
10								
11								
12	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,552.92	183.49	
13	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
14								
15	Total Overhead Transmission	Line Expenses				3,979.96	446.63	81
16		(230, 115, 69 Kv)						
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,979.96	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954/1081 KCM	174,960	2,279,762	2,454,722					1
1622ACSS TW								2
954 KCM ACSR	595,327	4,760,766	5,356,093					3
954 KCM ACSR	17,342	232,082	249,424					4
954 KCM ACSR		4,479	4,479					5
954 KCM ACSR		431,758	431,758					6
								7
								8
								9
								10
								11
	19,697,048	243,052,324	262,749,372					12
	88,132	11,739,339	11,827,471					13
								14
	41,848,845	495,022,374	536,871,219					15
				52,708	8,580,863		8,633,571	16
								17
								18
								19
								20
								21
								22
								23
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								28
								29
								30
								31
								32
								33
								34
								35
	41,848,845	495,022,374	536,871,219	52,708	8,580,863		8,633,571	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	Ultimate (g)
1	ICLW-3	Champions Gate	0.56	CP	15.00	1	1
2	Lake Luntz	Hemple	4.87	CP	15.00	1	1
3	Barcola	Pebbledale	3.86	CP	15.00	1	1
4	IO-418 (Tap)	Timberwood	1.50	CP	15.00	1	1
5	IO-342	Ross Prairie	5.64	CP	15.00	1	1
6	Hines Energy	Barcola	3.09	SP	15.00	1	1
7	WHX-58	TCEC Sub.	0.04	CP	15.00	1	1
8							
9							
10							
11							
12							
13							
14							
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41							
42							
43							
44	TOTAL		19.56		105.00	7	7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	AAC	V	69		303,419	128,096		431,515	1
795	AAC	V	69		3,282,284	914,142		4,196,426	2
1622	ACSSTW	V	230		2,324,754	1,103,202		3,427,956	3
795	AAC	V	69		562,460	174,551		737,011	4
795	AAC	V	69		1,272,815	476,260		1,749,075	5
954	ACSR	V	230		848,227	564,074		1,412,301	6
795	AAC	V	115		232,203	65,173		297,376	7
									8
									9
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									43
					8,826,162	3,425,498		12,251,660	44

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	32ND STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	51ST STREET - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	ALDERMAN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	BAYVIEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
6	BAYWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	BELLEAIR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	BROOKER CREEK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	CENTRAL PLAZA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	CROSS BAYOU - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	CROSSROADS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
13	CURLEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	DENHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
16			115.00	13.00	
17	DUNEDIN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	ELFERS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	FLORA MAR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
20	GATEWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
21	HIGHLANDS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	KENNETH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	MAXIMO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	NEW PORT RICHEY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
25	OAKHURST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	OLDSMAR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28			230.00	67.00	
29	PILSBURY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
30	PORT RICHEY WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	SAFETY HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
32	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
33			67.00	13.00	
34	SIXTEENTH ST. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	STARKEY ROAD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	TAYLOR AVE. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	TRI-CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	ULMERTON WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	VINOY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
40	WALSINGHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
60	2					2
80	2					3
90	3					4
100	2					5
40	1					6
80	2					7
60	2					8
60	2					9
120	4					10
150	3					11
80	2					12
90	3					13
90	3					14
150	1					15
80	2					16
60	3					17
100	2					18
100	2					19
90	3					20
80	2					21
60	2					22
150	3					23
60	2					24
90	3					25
15	2					26
60	2					27
200	1					28
100	2					29
90	3					30
80	2					31
250	1					32
100	2					33
80	2					34
80	2					35
80	2					36
60	2					37
80	2					38
100	2					39
100	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ZEPHYRHILLS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3			230.00	69.00	
4	ADAMS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	APPALACHICOLA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	BEACON HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
8	BELLEVIEW - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	BEVERLY HILLS - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	BUSHNELL - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	CARRABELLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	CENTER HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	CIRCLE SQUARE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	CITRUS HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	COLEMAN - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	CROSS CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	CRYSTAL RIVER NORTH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	DUNNELLON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	EAGLES NEST - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	EAST POINT - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	FLORAL CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	FOLEY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	GA PACIFIC - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	HAMMOCK - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
25			67.00	4.00	
26	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	HOMOSASSA- NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	INVERNESS - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
29			115.00	67.00	
30			67.00	13.00	
31	LADY LAKE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	LAKE WEIR - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
33	MADISON - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
34	MARICAMP - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	MARTIN - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	MONTICELLO - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
38			67.00	13.00	
39	ORANGE BLOSSOM - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
40	PERRY NORTH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
40	2					2
250	1					3
20	1					4
10	1					5
13	1					6
10	1					7
44	2					8
60	2					9
13	1					10
13	1					11
10	1					12
20	2					13
22	1					14
30	2					15
13	1					16
19	1					17
50	2					18
19	2					19
13	1					20
10	1					21
40	2					22
10	1					23
20	1					24
19	2					25
13	1					26
20	1					27
150	1					28
100	1					29
60	2					30
29	2					31
19	2					32
40	2					33
19	2					34
20	1					35
40	2					36
100	1					37
13	1					38
40	2					39
20	1					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PORT ST. JOE IND. - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	REDDICK - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	RIVER JUNCTION - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
4	ST. GEORGE ISLAND - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	SANTOS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	SILVER SPRINGS SHORE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	SOPCHOPPY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	ST MARKS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	TANGERINE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	TRENTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	TROPIC TERRACE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
12	TWIN COUNTY RANCH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
13	WAUKEENAH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	WEIRSDALE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	WILDWOOD CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	WILLISTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	WILLISTON TOWN - NORTH FLORIDA REGION	DIST - UNATTENDED	13.00	4.00	
18	ZUBER - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	ALAFAYA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	APOPKA SOUTH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	AVON PARK NORTH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	BABSON PARK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	BARBERVILLE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24			115.00	67.00	
25	BARNUM CITY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	BAY RIDGE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	BAYHILL - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	BITHLO - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	BOGGY MARSH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	BONNET CREEK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	CABBAGE ISLAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	CASSADAGA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	CASSELBERRY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	CELEBRATION - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	CENTRAL PARK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	CHAMPIONS GATE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	CITRUSVILLE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	CLARCONA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	CLEAR SPRINGS EAST - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
40			67.00	4.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS (Continued)

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20	1					1
22	2					2
19	1					3
20	1					4
13	1					5
40	2					6
10	1					7
10	1					8
60	2					9
10	1					10
40	2					11
22	2					12
20	1					13
19	2					14
28	1					15
13	1					16
10	2					17
29	2					18
60	2					19
90	3					20
40	2					21
20	1					22
40	2					23
23	1					24
19	1					25
40	2					26
90	3					27
50	2					28
40	2					29
60	2					30
21	2					31
60	2					32
120	3					33
60	2					34
90	3					35
20	1					36
20	1					37
90	3					38
20	1					39
19	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CLERMONT - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	CONWAY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	COUNTRY OAKS - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	CROOKED LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	CURRY FORD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
6	CYPRESSWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	DAVENPORT - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	DELAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	DELAND EAST - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	DELTONA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
11			115.00	13.00	
12	DELTONA EAST - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
13	DESOTO CITY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	DINNER LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	DOUGLAS AVENUE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	DUNDEE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	EAST LAKE WALES - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	EAST ORANGE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	EATONVILLE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	ECON - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
21	EUSTIS - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	EUSTIS SOUTH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	FERN PARK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	FISHEATING CREEK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
25			67.00	13.00	
26	FOUR CORNERS - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	FROSTPROOF - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	GROVELAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	HAINES CITY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	HEMPLE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	HOLOPAW - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	25.00	
32	HORSE CREEK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	15.00	
33	HOWEY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	HUNTERS CREEK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	INTERNATIONAL DRIVE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
36	ISLEWORTH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	KELLER ROAD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	LAKE ALOMA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39	SEBRING EAST - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
40	LAKE EMMA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
40	2					2
19	2					3
10	1					4
50	1					5
40	2					6
20	1					7
100	2					8
90	3					9
75	1					10
120	3					11
60	2					12
19	2					13
79	2					14
60	2					15
20	1					16
21	2					17
60	3					18
90	3					19
100	2					20
60	2					21
63	2					22
30	1					23
150	1					24
29	2					25
60	2					26
50	2					27
19	2					28
80	2					29
60	2					30
25	2					31
11	1					32
13	1					33
40	2					34
50	1					35
19	2					36
54	2					37
100	2					38
20	1					39
100	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LAKE HELEN - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	LAKE MARION - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	LAKE OF THE HILLS - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	LAKE PLACID - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	LAKE WALES - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	LAKE WILSON - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
7			67.00	13.00	
8	LAKEWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	LAKE LUNTZ - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	LEASURE LAKES - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	LIBSON - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	LOCKWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	LONGWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14	MAGNOLIA RANCH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
15	MAITLAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	MONTEVERDE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	MOUNT DORA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	MYRTLE LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
19	NARCOOSSEE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	NORTH FT. MEADE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
21	OCOEE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	OKAHUMPKA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	ORANGE CITY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	15.00	
24			115.00	13.00	
25	ORANGEWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
26	OVIEDO - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	PARKWAY - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	PINECASTLE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	PLYMOUTH - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	POINCIANNA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
31	REEDY LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	ROCKLAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	SAND LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	SHINGLE CREEK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
35	SKY LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
36			67.00	13.00	
37	SOUTH FT. MEADE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
38			115.00	25.00	
39	SPRING LAKE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	SUN' N LAKES - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	2					1
20	1					2
20	1					3
40	2					4
80	3					5
150	1					6
20	1					7
55	2					8
30	1					9
11	1					10
40	2					11
30	1					12
40	2					13
10	1					14
90	3					15
40	2					16
40	2					17
100	2					18
90	3					19
13	1					20
90	3					21
40	2					22
212	1					23
60	2					24
100	2					25
90	3					26
40	2					27
40	2					28
33	2					29
60	2					30
40	2					31
20	1					32
80	2					33
60	2					34
200	1					35
90	3					36
25	1					37
19	1					38
90	3					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TAFT - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	TAUNTON ROAD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	UMATILLA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
4	UNIV OF CENTRAL FLORIDA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	UNIV OF CENTRAL FLORIDA NORTH - CENTRAL FLORIDA	DIST - UNATTENDED	67.00	13.00	
6	VINELAND - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	WAUCHULA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
8	WEKIVA - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
9	WELCH ROAD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
10	WEST CHAPMAN - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	WEST DAVENPORT - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	WESTRIDGE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	WEWAHOOTEE - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
14			13.00	4.00	
15	WINTER GARDEN - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	WINTER PARK - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	WINTER PARK EAST - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
18			230.00	69.00	
19	WINTER SPRINGS - CENTRAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
20			67.00	13.00	
21	ZELLWOOD - CENTRAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	SUBSTATIONS AT VARIOUS LOCATIONS	DIST - UNATTENDED			
23	TOTAL DISTRIBUTION (278 SUBSTATIONS)		20009.00	3747.00	
24					
25	ANCLOTE PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
26			230.00	25.00	
27			230.00	4.16	
28			15.00	4.16	
29			15.00	25.00	
30			25.00	4.00	
31	BARTOW PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
32			230.00	13.00	
33	BAYBORO - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
34	EAST CLEARWATER - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
35			230.00	67.00	
36			115.00	67.00	
37			67.00	13.00	
38	HIGGINS PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
39			230.00	115.00	
40	HUDSON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
20	1					2
40	2					3
60	2					4
60	2					5
40	2					6
19	2					7
150	3					8
50	1					9
60	2					10
19	2					11
20	1					12
10	1					13
9	1					14
60	2					15
120	4					16
100	2					17
250	1					18
250	1					19
90	3					20
40	2					21
1116						22
13839	398					23
						24
100	2					25
1240	2					26
40	1					27
30	1					28
25	1					29
30	1					30
300	4					31
480	4					32
304	4					33
222	1					34
250	1					35
200	1					36
150	3					37
335	5					38
150	1					39
500	2					40

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LAKE TARPON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	500.00	230.00	13.00
2			500.00	230.00	
3	LARGO - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
4			230.00	67.00	
5	NORTHEAST - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
6			230.00	115.00	
7	PASADENA - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
8	PASADENA - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
9	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
10			230.00	115.00	
11	TARPON SPRINGS - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
12			115.00	67.00	
13	ULMERTON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
14			230.00	115.00	
15	ARCHER - NORTH FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
16			230.00	67.00	
17	BROOKRIDGE - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
18			500.00	230.00	13.00
19	BROOKSVILLE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
20			115.00	13.00	
21	BROOKSVILLE WEST - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
22	CENTRAL FLORIDA - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
23			500.00	230.00	13.00
24	CRAWFORDVILLE - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
25			67.00	7.00	
26	CRYSTAL RIVER EAST - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
27	CRYSTAL RIVER PLANT - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	25.00	
28			230.00	13.00	
29			500.00	25.00	
30	DRIFTON - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
31	FORT WHITE - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
32			67.00	13.00	
33			115.00	67.00	
34	GUMBAY - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
35	HAVANA - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
36	HOLDER - NORTH FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
37			230.00	115.00	
38			230.00	69.00	
39	IDYLWILD - NORTH FLORIDA REGION	TRANS - UNATTENDED	131.00	67.00	
40	INGLIS - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
750	1					1
750	1					2
100	2					3
600	3					4
100	2					5
400	2					6
250	1					7
80	2					8
60	2					9
750	3					10
100	2					11
150	1					12
100	2					13
400	2					14
10	2					15
150	1					16
500	2					17
750	1					18
250	2					19
60	2					20
250	1					21
450	2					22
1500	2					23
100	1					24
3	1					25
250	1					26
1850	4					27
80	2					28
1760	2					29
105	2					30
100	1					31
6	1					32
75	1					33
75	1					34
75	1					35
10	1					36
250	1					37
250	1					38
150	1					39
100	1					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1			67.00	13.00	
2	JASPER - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
3			67.00	13.00	
4	MARTIN WEST - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
5	PERRY - NORTH FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
6			230.00	67.00	
7	PORT ST. JOE - NORTH FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
8	PORT ST. JOE - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
9	QUINCY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
10	ROSS PRAIRIE - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
11	SILVER SPRINGS - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
12			67.00	13.00	
13	SUWANNEE 230KV - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	13.00	
14			230.00	115.00	
15	SUWANNEE RIVER PLANT - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
16	TALLAHASSEE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
17	WILCOX - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
18	ALTAMONTE - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
19			67.00	13.00	
20	AVON PARK PLANT - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
21			230.00	67.00	
22			115.00	69.00	
23			69.00	13.00	
24	BARCOLA - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
25	CAMP LAKE - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
26	CANOE CREEK - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	13.00	
27	CLERMONT EAST - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
28	DEBARY - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	13.00	
29	DELAND WEST - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
30			115.00	67.00	
31	FORT MEADE - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
32			67.00	13.00	
33			115.00	67.00	
34			230.00	115.00	
35	GRIFFIN - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
36	HAINES CREEK - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
37	HINES ENERGY COMPLEX - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	16.00	
38	INTERCESSION CITY - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
39			230.00	13.00	
40			230.00	67.00	

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
9	1					1
45	1					2
14	1					3
200	1					4
40	2					5
250	2					6
40	2					7
200	2					8
75	1					9
250	1					10
250	1					11
20	1					12
256	2					13
400	2					14
178	4					15
120	2					16
150	1					17
200	1					18
100	2					19
49	3					20
200	1					21
150	1					22
64	1					23
150	1					24
150	1					25
30	1					26
250	1					27
835	7					28
200	1					29
125	1					30
200	1					31
10	1					32
60	1					33
150	1					34
150	1					35
250	1					36
615	3					37
335	4					38
955	8					39
250	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2003	Dec. 31, 2003

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KATHLEEN - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	500.00	230.00	13.00
2	LOCKHART - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	13.00	
3	MEADOW WOODS SO. - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
4			67.00	13.00	
5	NORTH BARTOW - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
6	NORTH LONGWOOD - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	13.00	
7			230.00	67.00	
8			230.00	115.00	
9	NORTH LONGWOOD - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
10	PIEDMONT - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
11			230.00	67.00	
12	RIO PINAR - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
13			67.00	13.00	
14	SORRENTO - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
15	TURNER PLANT - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	115.00	13.00	
16			115.00	67.00	
17			67.00	13.00	
18	VANDOLAH - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
19	WEST LAKE WALES - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	67.00	13.00	
20			230.00	67.00	
21	WINDERMERE - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
22			67.00	13.00	
23			67.00	2.00	
24	WOODSMERE - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	67.00	
25			67.00	13.00	
26	LAKE BRYAN - CENTRAL FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
27			67.00	13.00	
28	SUBSTATIONS AT VARIOUS LOCATIONS				
29					
30	TOTAL TRANSMISSION (90 SUBSTATIONS)		22113.00	7039.32	52.00
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2003	Year of Report Dec. 31, 2003

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
750	1					1
100	2					2
200	1					3
50	2					4
150	1					5
100	2					6
250	1					7
150	1					8
150	1					9
100	2					10
250	1					11
350	2					12
120	3					13
250	1					14
325	3					15
160	2					16
60	3					17
400	2					18
13	1					19
250	1					20
200	1					21
19	2					22
1	1					23
250	1					24
40	2					25
400	2					26
90	3					27
						28
						29
31258	214					30
						31
						32
						33
						34
						35
						36
						37
						38
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Florida Public Service Commission

Diversification Report

Florida Power Corporation

December 31, 2003

SIGNATURE PAGE

I certify that I am the responsible accounting officer of
FLORIDA POWER CORPORATION
that I have examined the following report; that to the best of my knowledge, information, and belief, all statements of fact contained in the said report are true and the said report is a correct statement of the business and affairs of the above-named respondent in respect to each and every matter set forth therein during the period from January 1, 2003 to December 31, 2003, inclusive.

I also certify that all affiliated transfer prices and affiliated cost allocations were determined consistent with the methods reported to this Commission on the appropriate forms included in this report.

I am aware that Section 837.06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

4/29/04

Date

Signature

Mark A. Myers

Name

Vice President, Finance

Title

Affiliation of Officers and Directors

Company: Florida Power Corporation

For the Year Ended December 31, 2003

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person excercising similar functions

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Name and Address
Robert H. Bazemore, Jr.	Vice President, Controller	None	
William Cavanaugh III	Director, Chairman of the Board	Board of Directors	Duke Realty Corp. Indianapolis, IN
		Governing Board	World Association of Nuclear Operators London, UK
		Chairman	World Association of Nuclear Operators - Atlanta Center Atlanta, GA
		Advisory Board	Tulane University, School of Engineering New Orleans, LA
		Board of Visitors	University of North Carolina Kenan Flagler School of Business Chapel Hill, NC
		Board of Directors	Research Triangle Foundation Research Triangle Park, NC
Geoff Chatas	Executive Vice President Chief Financial Officer	None	
Fred N. Day, IV	President & Chief Executive Officer Progress Energy Carolinas	Director	Palmetto Business Forum Columbia, SC 29211
		Director	Advanced Energy Corporation Raleigh, NC
		Director	NC State Engineering Foundation Raleigh, NC
		Director	NC Zoological Society Asheboro, NC
		Director	Greater Triangle Regional Council Research Triangle Park, NC

Affiliation of Officers and Directors

Company: Florida Power Corporation
For the Year Ended December 31, 2003

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person excercising similar functions.

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Name and Address
		Chairman	Greater Raleigh Chamber of Commerce Raleigh, NC
		Director	Assoc. of Edison Illuminating Companies Birmingham, AL
C. S. Hinnant	Senior Vice President & Chief Nuclear Officer	Director	Carolinas Virgina Nuclear Power Assoc. Columbia, SC
		Vice President	Advanced Reactor Corp. District of Columbia
H. William Habermeyer, Jr.	Director, President, CEO	Board Member & Vice Chair	Enterprise Florida Orlando, FL
		Board Member	Pinellas Co. Board of Education Largo, FL
		Board Member	Florida Chamber of Commerce Tallahassee, FL
		Board Member	Tampa Bay Partnership Tampa, FL
		Board Member	Florida Council for Economic Education Tampa, FL
		Director	Raymond James Financial, Inc. St. Petersburg, FL
		Officer	Florida Electric Power Coordinating Group Tampa, FL
		Board Member	USF Foundation Board of Trustees Tampa, FL

Affiliation of Officers and Directors

Company: Florida Power Corporation
For the Year Ended December 31, 2003

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person excercising similar functions

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership	
		Affiliation or Connection	Name and Address
		Trustee	Salvador Dali Museum St. Petersburg, FL
		Board Member	Boys & Girls Club of the Suncoast St. Petersburg, FL
		Board Member	Museum of Fine Arts St. Petersburg, FL
William D. Johnson	Group President Energy Delivery	Trustee	Meredith College Raleigh, NC
		Board Member	Golden LEAF Raleigh, NC
		Board Member	National Coal Council Washington, DC
		Board Member	Daugherty Endowment Fund Raleigh, NC
		Board Member	Triangle Opera Raleigh, NC
Jeff Lyash	Senior Vice President Energy Delivery Florida	None	
John R. McArthur	Senior Vice President General Counsel & Secretary	Board of Directors	Easter Seals UCP Raleigh, NC
Robert B. McGehee	President and COO	Board Member	Carolina Ballet Raleigh, NC
		Board Member	INPO Atlanta, GA
		Board Member	NEI Washington, DC

Affiliation of Officers and Directors

Company: Florida Power Corporation
For the Year Ended December 31, 2003

For each of the officials named in Part 1 of the Executive Summary, list the principal occupation or business affiliation if other than listed in Part 1 of the Executive Summary and all affiliations or connections with any other business or financial organizations, firms, or partnerships. For purposes of this part, the official will be considered to have an affiliation with any business or financial organization, firm or partnership in which he is an officer, director, trustee, partner, or a person excercising similar functions

Name	Principal Occupation or Business Affiliation	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Affiliation or Connection	Affiliation or Connection with any Other Business or Financial Organization Firm or Partnership: Name and Address
William S. Orser	Director, Group President Energy Supply	Board Member	Assoc. of Edison Illuminating Companies Birmingham, AL
		Board Member	NC Partnership for Excellence Morrisville, NC
		President of Board of Directors	Food Bank of North Carolina Raleigh, NC
		Trustee	Montreat College Montreat, NC
		Co-Chair	The Nature Conservancy Durham, NC
Peter M. Scott III	Director, CFO	Brd of Governors Vice Chair	Capital City Club Raleigh, NC
		Director	North Carolina Museum of Art Foundation Raleigh, NC
		Brd of Governors Member	Research Triangle Institute Research Triangle Park, NC
Frank A. Shiller	Vice President - Legal, General Counsel	None	
E. Michael Williams	Senior Vice President	None	

Business Contracts with Officers, Directors and Affiliates

Company: Florida Power Corporation
For the Year Ended December 31, 2003

List all contracts, agreements, or other business arrangements* entered into during the calendar year (other than compensation-related to position with respondent) between the respondent and each officer and director listed in Part 1 of the Executive Summary. In addition, provide the same information with respect to professional services for each firm, partnership, or organization with which the officer or director is affiliated.

Note: * Business agreement, for this schedule, shall mean any oral or written business deal which binds the concerned parties for products or services during the reporting year or future years.

Name of Officer or Director	Name and Address of Affiliated Entity	Amount	Identification of Product or Service
H. William Habermeyer, Jr.	Enterprise Florida Orlando, FL	1,000	Donation
	Florida Chamber of Commerce Tallahassee, FL	35,000	Donation
	Tampa Bay Partnership Tampa, FL	2,000	Donation
	Florida Electric Power Coordinating Group Tampa, FL	52,640	Dues
	Salvador Dali Museum St. Petersburg, FL	2,750	Donation
	Museum of Fine Arts St. Petersburg, FL	1,500	Donation
William S. Orser	The Nature Conservancy Durham, NC	100	Donation

Reconciliation of Gross Operating Revenues
Annual Report versus Regulatory Assessment Fee Return

Company: *Florida Power Corporation* *For the Year Ended December 31, 2003*

For the current year, reconcile the gross operating revenues as reported on Page 300 of this report with the gross operating revenues as reported on the utility's regulatory assessment fee return. Explain and justify any differences between the reported gross operating revenues in column (h).

Line No.	(a) Description	(b) Gross Operating Revenues per Page 300	(c) Interstate and Sales for Resale Adjustments	(d) Adjusted Intrastate Gross Operating Revenues	(e) Gross Operating Revenues per RAF Return	(f) Interstate and Sales for Resale Adjustments	(g) Adjusted Intrastate Gross Operating Revenues	(h) Difference (d) - (g)
1	Total Sales to Ultimate Customers (440-446, 448)	$ 2,830,809,013	$ 41,913,284	$ 2,788,895,729	$ 2,830,809,013	$ 41,913,284	$ 2,788,895,729	$ -
2	Sales for Resale (447)	228,334,215	228,334,215	0	228,334,215	228,334,215	0	-
3	Total Sales of Electricity	3,059,143,228	270,247,499	2,788,895,729	3,059,143,228	270,247,499	2,788,895,729	-
4	Provision for Rate Refunds (449.1)	(36,332,666)	(1,124,462)	(35,208,204)	(36,332,666)	(1,124,462)	(35,208,204)	-
5	Total Net Sales of Electricity	3,022,810,562	269,123,037	2,753,687,525	3,022,810,562	269,123,037	2,753,687,525	-
6	Late Payment Charge (450)	8,388,053		8,388,053	8,388,053		8,388,053	-
	Miscellaneous Service Revenue (451)	20,647,127		20,647,127	20,647,127		20,647,127	-
7	Rent from Electric Property (454)	56,020,586		56,020,586	56,020,586		56,020,586	-
8	Deferred Capacity & Fuel Revenue (4560097, 99)	(10,875,268)		(10,875,268)	(10,875,268)		(10,875,268)	-
9	Unbilled Revenues	(1,795,048)	1,201,190	(2,996,238)	(1,795,048)	1,201,190	(2,996,238)	-
10	Wheeling Revenue	42,165,032	42,165,032	-	42,165,032	42,165,032	-	-
11	Other Electric Revenue Interchange Sales	937,053	937,053	0	937,053	937,053	0	-
12	Other Miscellaneous Revenue	2,535,083		2,535,083	2,535,083		2,535,083	-
13	Total Other Electric Revenue	118,022,618	44,303,275	73,719,342	118,022,618	44,303,275	73,719,342	-
14								
15	**Total Gross Operating Revenues**	$ 3,140,833,180	$ 313,426,313	$ 2,827,406,867	$ 3,140,833,180	$ 313,426,313	$ 2,827,406,867	$ -

Notes:

(A) Included in the gross operating revenues are credits related to load management, interruptible services and curtailable service programs. These credits reduce the customers' bills. The revenues related to the credits are included in FPC's gross operating revenues for accounting purposes twice; once through the ECCR recovery collections and again through revenues which are recorded gross of the credits.

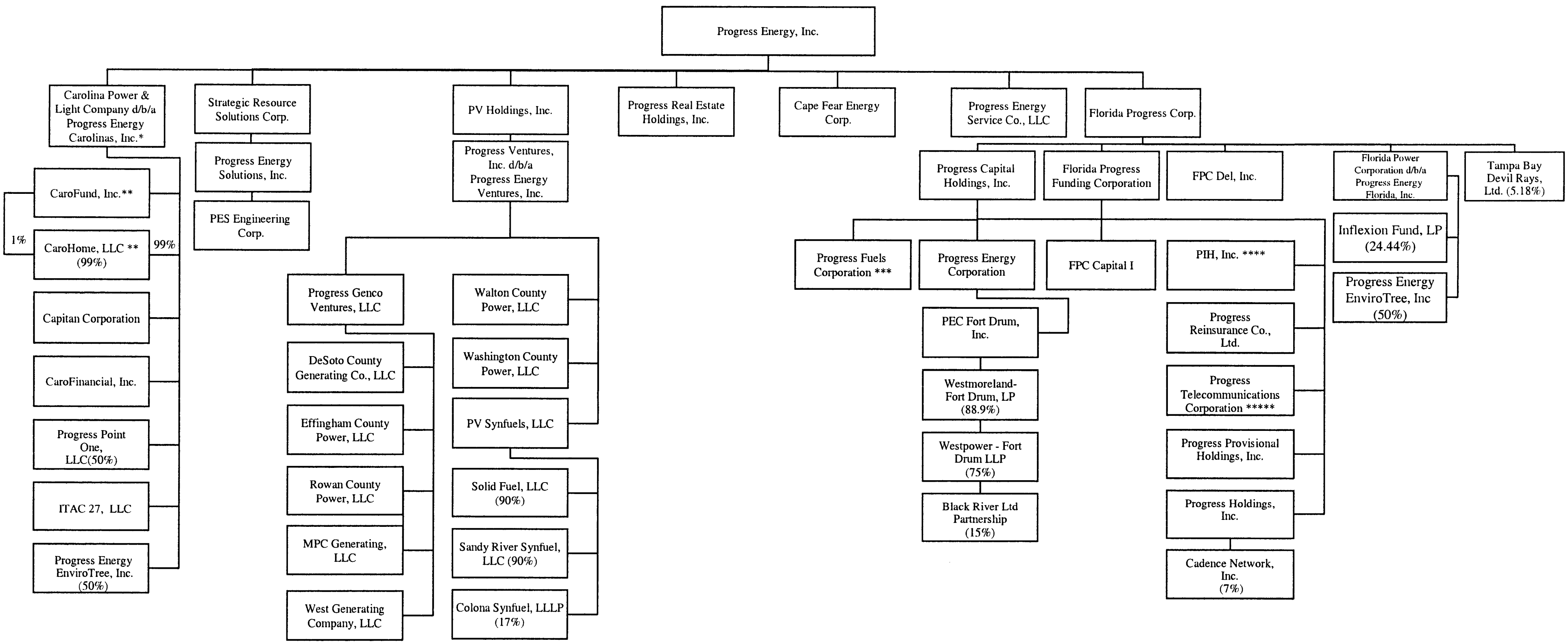
Analysis of Diversification Activity
Changes in Corporate Structure

Company: ***Florida Power Corporation***
For the Year Ended December 31, 2003

Provide any changes in corporate structure including partnerships, minority interest, and joint ventures and an updated organizational chart, including all affiliates.

Effective Date (a)	Description of Change (b)
2/5/2003	Formed Progress Fuels North Texas Gas, LP
2/10/2003	Progress-Centrus, Inc. dissolved
2/10/2003	Energy Solutions, Inc. dissolved
2/10/2003	Cincinnati Bulk Terminals, Inc. changed its name to KRT Holdings, Inc.
2/14/2003	Baldwin County Ventures, LLC dissolved
3/31/2003	Formed Mesa Hydrocarbons Acquisition, LLC
4/7/2003	Changed name of Mesa Hydrocarbons Acquisition, LLC to Mesa Hydrocarbons, LLC
4/8/2003	Mesa Hydrocarbons, Inc. was merged into Mesa Hydrocarbons Acquisition, LLC
4/8/2003	PRS International Sales Company, Inc. dissolved
5/1/2003	CPL Synfuels, LLC changed its name to PV Synfuels, LLC
5/15/2003	PIH Tax Credit Funds I, II, VI and VII dissolved
6/17/2003	Progress Desal, Inc. dissolved
6/17/2003	Progress Power Marketing dissolved
8/31/2003	Kentucky May Mining Company merged into Kentucky May Coal Company, Inc.
8/31/2003	Powell Mountain Joint Venture dissolved
9/30/2003	KRT Holdings, Inc. merged into Kanawha River Terminals, Inc.
9/30/2003	Awayland Coal Company, Inc. and Homeland Coal Company, Inc. merged into Powell Mountain Coal Company, Inc.
9/24/2003	PEC MGP, LLC and PEC Communications, LLC were formed as subsidiaries of North Carolina Natural Gas Corp.
9/30/2003	PEC MGP, LLC and PEC Communications, LLC were contributed to Progress Energy Carolinas, Inc.
9/30/2003	Stock of North Carolina Natural Gas Corp., NCNG Cardinal Pipeline Investment Corp. and NCNG Pine Needle Investment Corp. sold to an unrelated third party
9/30/2003	Progress Energy, Inc's 50% stake in Eastern North Carolina Natural Gas was sold to a third party
9/30/2003	Cape Fear Energy Corp. was distributed to Progress Energy, Inc.
10/31/2003	3079936 Nova Scotia Company was formed
11/4/2003	Progress Telecom Corporation was converted to an LLC and renamed Progress Telecom, LLC
12/19/2003	Progress Telecommunications Corporation, Caronet, Inc. and EPIK Telecommunications, Inc. (an unrelated third party) contributed telecom assets to Progress Telecom, LLC in exchange for interests in Progress Telecom, LLC of 55%, 5% and 45% respectively
12/19/2003	Carolina Power & Light Company sold 100% of its Caronet, Inc. stock to EPIK Telecommunications, Inc.
12/22/2003	Progress Energy EnviroTree, Inc. was formed with ownership as follows: Florida Power Corporation (50%) and Carolina Power & Light Company (50%)
12/30/2003	ProgressCenter, LLC and Progress Center II, LLC merged into Progress Real Estate Holdings, In(
12/30/2003	PEC Communications, LLC and PEC MGP, LLC merged into Carolina Power & Light Company

Progress Energy, Inc.
Corporate Legal Entity Structure



* Excludes passive investments held by CP&L in low-income housing projects, venture capital projects, enterprise development projects, etc. – see page 7.

** CaroHome LLC and CaroFund, Inc. own various interests in low-income housing and historical properties-see page 8.

*** See Progress Fuels subsidiaries on pages 2, 3, and 4.

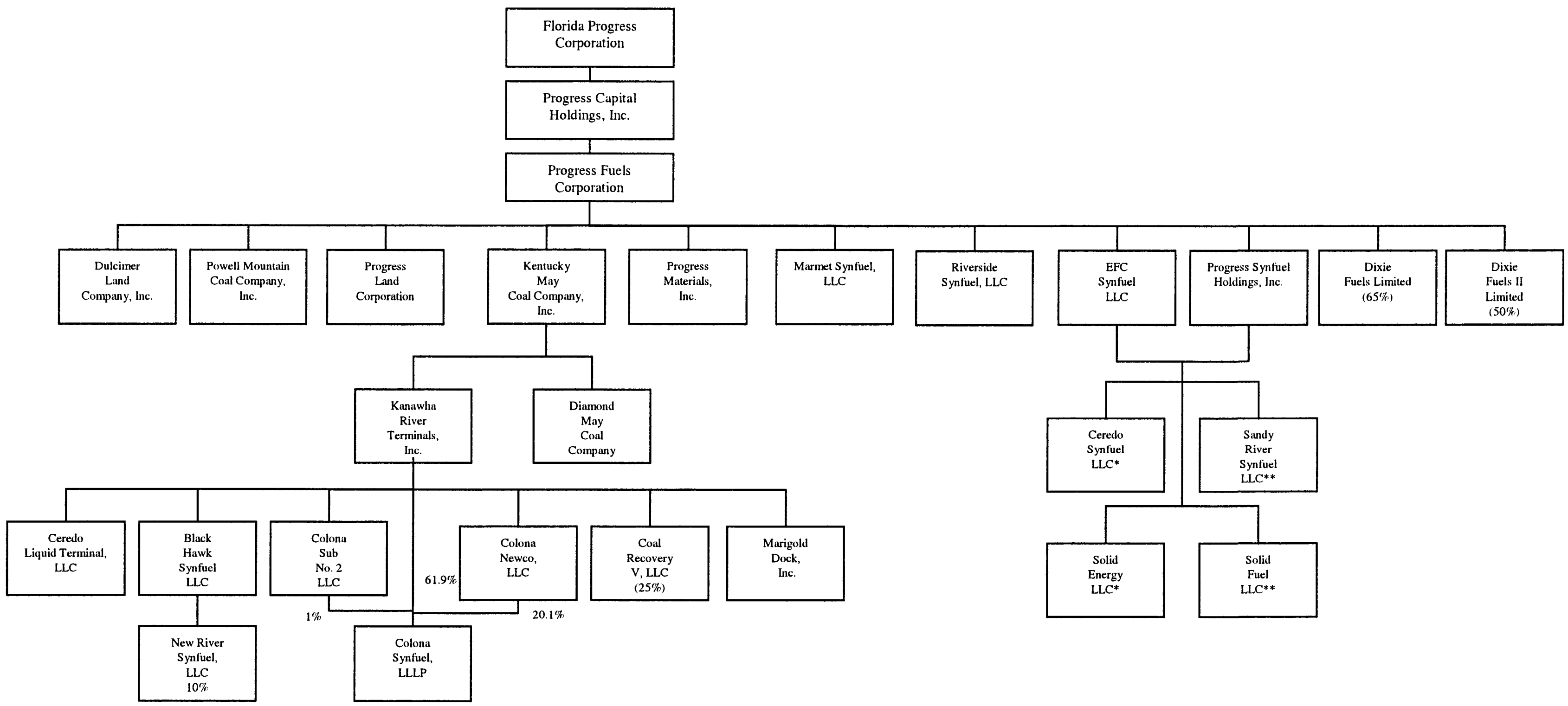
**** See PIH subsidiaries on page 5.

***** See Progress Telecommunications subsidiaries on page 6.

Note: Progress Energy or its subsidiaries own 100% of the voting securities of the subsidiaries or associate companies shown on the chart unless otherwise noted with other percentage interests.

12-31-03

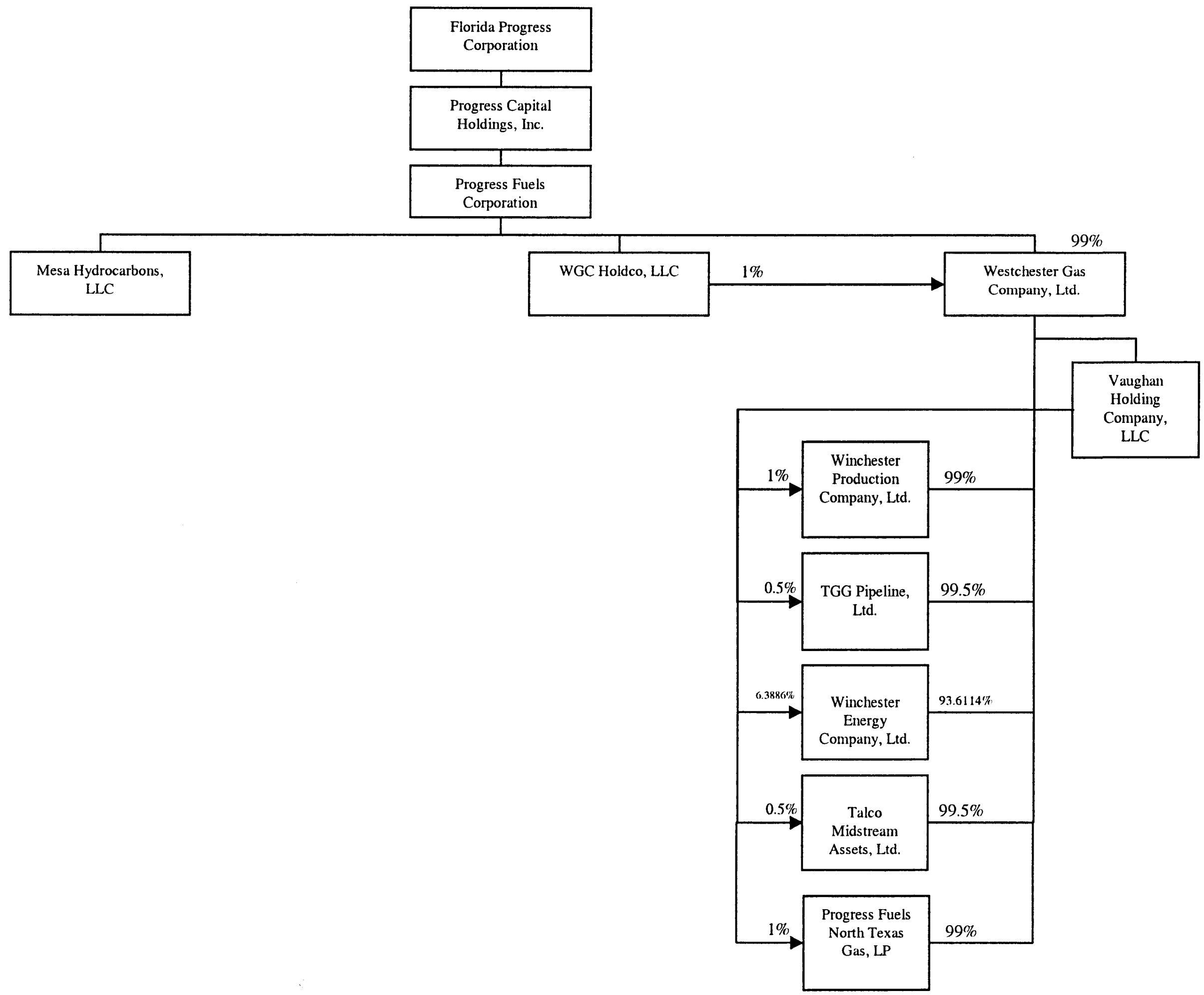
Progress Fuels Corporation
Energy & Related Services Group



* EFC Synfuel LLC and Progress Synfuel Holdings, Inc. own 99% and 1%, respectively.
** EFC Synfuel LLC and Progress Synfuel Holdings, Inc. own 9% and 1%, respectively.

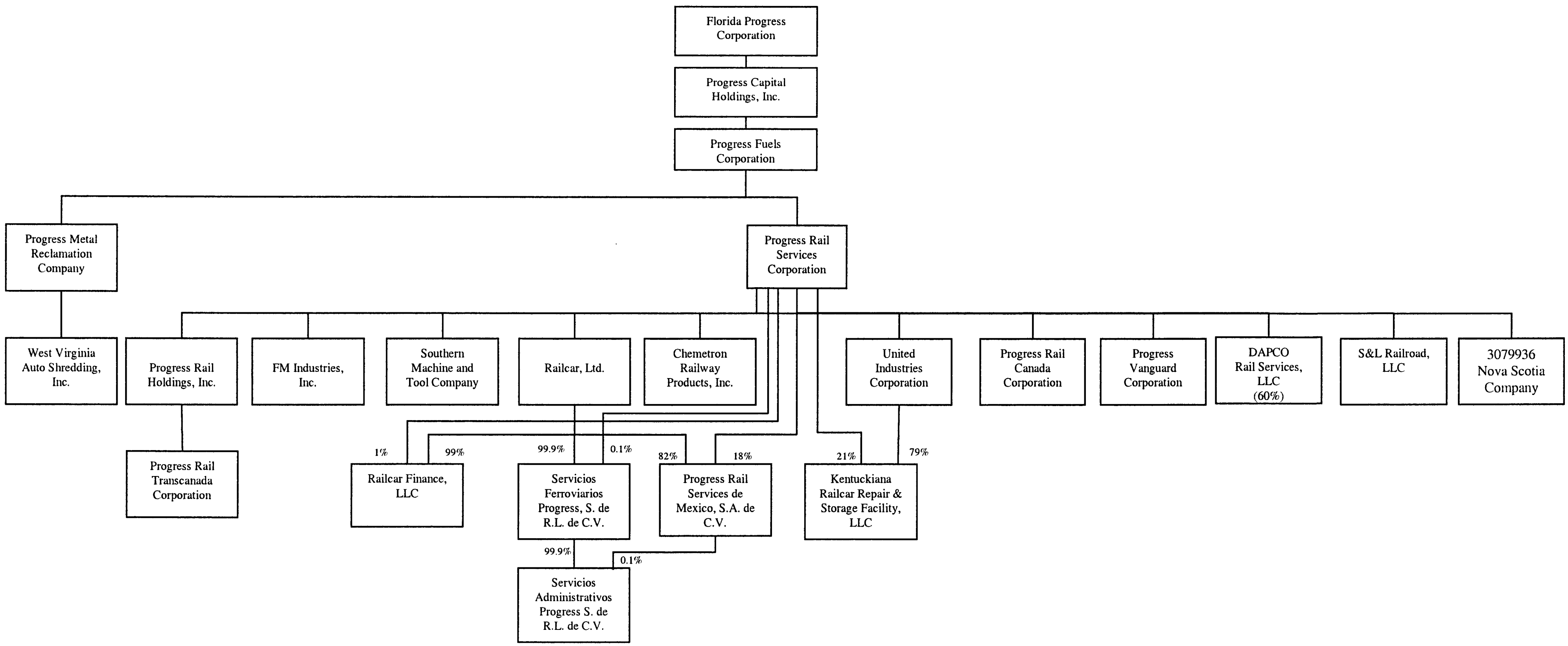
12-31-03

Progress Fuels Corporation
Gas Operations Group



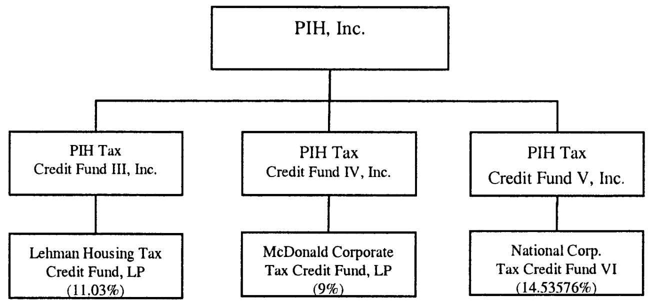
12-31-03

Progress Fuels Corporation
Rail Services Group

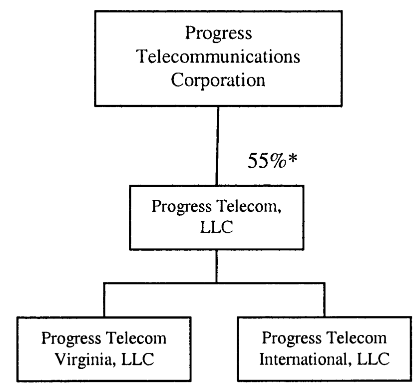


12-31-03

PIH, Inc.


PIH, Inc.
PIH Tax
Credit Fund III, Inc.
PIH Tax
Credit Fund IV, Inc.
PIH Tax
Credit Fund V, Inc.
Lehman Housing Tax
Credit Fund, LP
(11.03%)
McDonald Corporate
Tax Credit Fund, LP
(9%)
National Corp.
Tax Credit Fund VI
(14.53576%)

Telecommunications Group

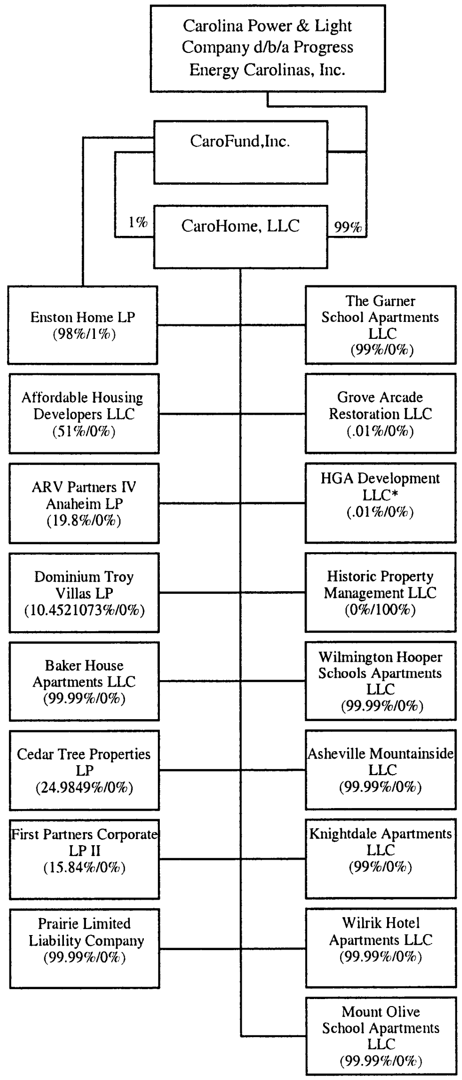


* Remaining 45% interest is owned by EPIK Communications, Inc., an unrelated third party

Progress Energy Carolinas (CP&L)
Other Investments

- Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
  - Powerhouse Square, LLC (100%)
  - Palmetto Seed Capital Fund, LP (3.676470%)
  - North Carolina Enterprise Fund, LP (5.00877%)
  - Absolut LP (99%)
  - Capital City Low Income Housing LP (99%)
  - NC Enterprise Corporation (4.97%)
  - Walnut Street LP (99%)
  - Utech Climate Challenge Fund LP (9.76%)
  - Carousel Capital Partners LP (3.06857%)
  - Better Homes for Garner LP (99%)
  - Kinetic Ventures I LLC (11.111111%)
  - Maxey Flats LLC (3%)
  - Pantellos Corporation (1%)
  - Kinetic Ventures II, LLC (14.282715%)
  - South Atlantic Private Equity Fund IV, LP (10.133794%)
  - Utech Venture First II LP (9.76%)
  - WNC Institutional Tax Credit Fund LP (99%)
  - EBS Litigation LLC (0.00126%)
  - EBS, Pension, LLC (0.00126%)
  - EBS Building LLC (0.00126%)
  - Southeast Regional Park Industrial Development Company, LLC (33.33%)

CaroHome / CaroFund Investments



Note: CaroHome % listed first, then CaroFund %

*: Also owned 0.01% by Historic Property Management LLC

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at a minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
Progress Telecom LLC	The contract governs the lease and use by Progress Telecom (PT) of Progress Energy Florida (PEF) facilities for the wireless communications attachment business on a wholesale basis so, in turn, PT may lease space and provide other related services to third parties on the property of PEF, whether on electrical structures, microwave towers, communication towers, transmission and distribution towers, buildings or other land assets. PT shall have the exclusive right to acquire access to PEF's property for the purpose of attaching third party wireless communications facilities to such PEF property. The agreement will remain in effect for 25 years. PT will pay PEF $350,000 per year, and pass back 30% of the revenue from 3rd party attachments.

Analysis of Diversification Activity
Individual Affiliated Transactions in Excess of $500,000

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Provide information regarding individual affiliated transactions in excess of $500,000. Recurring monthly affiliated transactions which exceed $500,000 per month should be reported annually in the aggregate. However, each land or property sales transaction even though similar sales recur, should be reported as a "non-recurring" item for the period in which it occurs.

Name of Affiliate (a)	Description of Transaction (b)	Dollar Amount (c)
Progress Energy Service Company	Benefits, accounting, tax, legal, IT, HR, telecommunications, treasury executive, corporate communications, advertising, public safety, environmental services, facilities and real estate management	236,477,547
Progress Fuels Corporation	Coal purchases for CR 1, 2, 4 & 5	346,188,283

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Grouped by affiliate, list each contract, agreement, or other business transaction exceeding a cumulative amount of $300 in any one year, entered into between the Respondent and an affiliated business or financial organization, firm, or partnership identifying parties, amounts, dates, and product, asset, or service involved.
(a) Enter name of affiliate.
(b) Give description of type of service, or name the product involved.
(c) Enter contract or agreement effective dates.
(d) Enter the letter "p" if the service or product is purchased by the Respondent: "s" if the service or product is sold by the Respondent.
(e) Enter utility account number in which charges are recorded.
(f) Enter total amount paid, received, or accrued during the year for each type of service or product listed in column (c). Do not net amounts when services are both received and provided.

Name of Affiliate (a)	Type of Service and/or Name of Product (b)	Relevant Contract or Agreement and Effective Date (c)	"p" or "s" (d)	Total Charge for Year: Account Number (e)	Total Charge for Year: Dollar Amount (f)
Progress Energy Carolina	Gas Purchases		P	1512000	15,662,769
	Mgmt & IT services,		P	2340001	34,512,188
	Fuel procurement,				
	Mgmt services, Customer				
	Service Support		S	1460001	7,479,125
Progress Fuels Corporation	Payroll Services, rent		S	1460061	1,634,473
	Coal-CR 1,2,3 &4		P	1511010	142,055,231
	Coal-CR 1,2,3 &4, Outside		P	2340061	204,133,052
	Services				
Progress Ventures	Payroll, Materials				
	Outside Services		S	1460020	30,509
Progress Genco Ventures	Mgmt Support		S	1460023	1,064,944
No. Carolina Natural Gas	Payroll		S	1460050	10,874
Progress Energy Holding Company	Restricted Stock		P	2340099	1,352,923
Progress Energy Service Company	Employee Benefits				
	Legal / IT / Acctg Svcs,				
	Telecom, HR, Corp Comm,				
	Corporate Mgmt		P	2340098	236,477,547
	Labor costs		S	1460098	20,503,293
Florida Progress Corporation	Federal and State Income				
	Tax		S	1460063	35,973,184
	Federal and State Income				
	Tax		P	2340063	204,810,520
Progress Telecommunications	Materials, Freight,		S	1460062	4,641,515
	Outside Svcs				
	Network Services		P	2340062	1,291,141
Progress Capital Holding	Tax		S	1460064	666
Progress Materials	Sale of Fly Ash				
	Potable/Process Water		S	147	760,707

Analysis of Diversification Activity
Assets or Rights Purchased from or Sold to Affiliates

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Provide a summary of affiliated transactions involving asset transfers or the right to use assets.

Name of Affiliate	Description of Asset or Right	Cost/Orig. Cost	Accumulated Depreciation	Net Book Value	Fair Market Value	Purchase Price	Title Passed Yes/No
Purchases from Affiliates:							
Progress Telecom	**Communication Equipment**	**$ 24,474,383**	**$ 14,957,610**	**$ 9,516,773**	**(A)**	**(B)**	**Yes**
Progress Energy Carolina	**Radios for Energy Delivery**	**$ 527,611**	**$ 25,002**	**$ 502,609**	**$ 502,609**	**$ 502,609**	**Yes**
Total		**$ 25,001,994**	**$ 14,982,612**	**$ 10,019,382**	**$ 502,609**	**$ 502,609**	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
None							
Total						$	

(A) Contingent upon a 3rd Party appraisal due within 180 days of effective date of agreement (12/31/2003).

(B) Final Purchase Price to be determined by lower of cost or Market Value established by appraisal mentioned in Note A.

Analysis of Diversification Activity
Employee Transfers

Company: Florida Power Corporation
For the Year Ended December 31, 2003

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
FPC	SVC	Admin Asst to Department Head	Admin Asst to Department Head	Permanent
SVC	FPC	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
FPC	SVC	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
FPC	CPL	Asset Spec-ED	Sr EDG Service Spec	Permanent
FPC	CPL	Assistant Plant Operator	Auxiliary Oper A	Permanent
FPC	SVC	Assoc Telecom Anlyst	Assoc Telecom Anlyst	Permanent
FPC	CPL	Bus Fin Anlyst	Bus Fin Anlyst	Permanent
PVI	FPC	Combustion Turbine Tech II	Comb Turbine Technician	Permanent
FPC	CPL	Engr	Engr	Permanent
CPL	FPC	Gen Mgr-Distribution	Gen Mgr-Distribution	Permanent
CPL	FPC	I&C Tech I-Nuc	I&C Tech I-Nuc	Permanent
FPC	SVC	Lead Reg Affairs Anlyst	Lead Reg Affairs Anlyst	Permanent
FPC	CPL	Lead Tech Proj Mgmt Spec	Lead Tech Proj Mgmt Spec	Permanent
CPL	FPC	Lead Work Mgmt Spec	Lead Work Mgmt Spec	Permanent
CPL	FPC	Lineman 1/C	Lineman 1/C	Permanent
FPC	CPL	Lineman-System Transmission	Lineman 1/C	Permanent
PTC	FPC	Mgr-Cust Service Delivery-PTC	DCC Shift Supervisor	Permanent
FPC	PTC	Mgr-EnergyDeliveryBusOps (IO)	Dir-Proc,Deploy,Tax-PTC	Permanent
FPC	SVC	Mgr-Florida Regulatory Affairs	Mgr-Florida Regulatory Affairs	Permanent
CPL	FPC	Mgr-Fuel Operations	Mgr-Fuel Operations	Permanent
SVC	FPC	Mgr-HR Energy Delivery-FL	Sr Energy Del Process Anlyst	Permanent
SVC	FPC	Mgr-IT Customer Support	Mgr-Network Services-FL	Permanent
FPC	CPL	Mgr-Maintenance NGG-CRP	Mgr-Shift Maint-Roxboro (IO)	Permanent
FPC	SVC	Mgr-Network Services-FL	Mgr-Network Services-FL	Permanent
FPC	SVC	Mgr-Public Policy & Constituen	Mgr-Public Policy & Constituen	Permanent
CPL	FPC	Mgr-PwrSystOpsTraining	Mgr-Power Sys Ops-Fl	Permanent
FPC	SVC	Mgr-Regulatory Policy-FL	Mgr-Regulatory Policy-FL	Permanent
FPC	SVC	Mgr-Strategic Support	Mgr-Strategic Support	Permanent
CPL	FPC	Mgr-Trans Equipment	Mgr-Transmission Area Maint	Permanent
PTC	FPC	OSP Engr Spec IV-PTC	Sr Engr	Permanent
EFC	FPC	Princ Tech Proj Mgmt Spec	Princ Tech Proj Mgmt Spec	Permanent
FPC	SVC	Public Policy Analyst-CRAS	Public Policy Analyst-CRAS	Permanent
CPL	FPC	Relay Tech I	Relay Tech I	Permanent
FPC	CPL	Shift Supv-FGD	Supt-Shift Operations-Roxboro	Permanent
FPC	CPL	Shift Supv-FGD	Supt-Maintenance-FGD	Permanent
PTC	FPC	Sr Administrative Assistant-FL	Sr Administrative Assistant-FL	Permanent
SVC	FPC	Sr Auditor	Lead Bus Fin Anlyst	Permanent
PVI	FPC	Sr Comb Turbine Tech	Sr Comb Turbine Tech	Permanent
FPC	CPL	Sr Data Management Asst-FL	Nuc Materials Assistant	Permanent
FPC	CPL	Sr Engr	Sr Engr	Permanent
CPL	FPC	Sr Engr	Sr Engr	Permanent
PTC	FPC	Sr Financial Support Asst-FL	Customer Service Agent I-FL	Permanent
SVC	FPC	Sr Human Resources Spec	Shift Supv-Region	Permanent
SVC	FPC	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
SVC	FPC	Sr Security Spec	Sr Tech Constr Inspector	Permanent
CPL	FPC	Sr Tech Proj Mgmt Spec	Supv-I&C-FGD-R (06/06)	Permanent
PTC	FPC	Sr Technical Staff Spec-PTC	Telecomms Tech	Permanent
SVC	FPC	Sr Telecom Anlyst	Supv-Telecomm Ops	Permanent
FPC	SVC	Sr Telecom Anlyst	Sr Telecom Anlyst	Permanent
CPL	FPC	Supt-Security	Supt-Security	Permanent
FPC	SVC	Supv-Cent Maint-Wldwd	Lead Proj Specialist-CORP SVCS	Permanent
FPC	CPL	Supv-I&C-FGD	Sr Engr	Permanent
CPL	FPC	Supv-Nuc Records/Doc Control	Supv-Nuc Records/Doc Control	Permanent
FPC	SVC	Supv-Telecomm Ops	Lead Telecom Anlyst	Permanent
CPL	FPC	Sys Operator II	Sr Engr	Permanent
FPC	CPL	Tech Proj Mgmt Spec	Tech Proj Mgmt Spec	Permanent
FPC	SVC	Telecomm Matl & Inv Spec I	Telecomm Matl & Inv Spec I	Permanent
FPC	SVC	Telecomm Matl & Inv Spec II	Telecomm Matl & Inv Spec II	Permanent
FPC	SVC	VP-CorpRelations&AdminSvcs-Fl	VP-CorpRelations&AdminSvcs-FL	Permanent
CPL	FPC	VP-Transmission (Carolina)	Sr VP-Energy Delivery-FL	Permanent
CPL	FPC	Supv-DIS Support	Supv-DIS Support	Permanent
FPC	SVC	Supv-Meter Reader	Supv-Meter Reader	Permanent

Analysis of Diversification Activity
Non-Tariffed Services and Products Provided by the Utility

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Provide the following information regarding all non-tariffed services and products provided by the utility.

Description of Product or Service (a)	Account No. (b)	Regulated or Non-regulated (c)
Wireless Transmission Tower Attachments	4540000	Regulated
Rent from Electric Properties	4540000	Regulated
PCS Engineering Design and Construction	4170000	Non-Regulated
Managed Services	4210000	Non-Regulated
Turnkey Solutions	4210000	Non-Regulated
Power Quality Services	4210000	Non-Regulated
Homewire	4210000	Non-Regulated
Lighting	4210000	Non-Regulated
Infrared Scanning Services	4170000	Non-Regulated
High Voltage Services	4170000	Non-Regulated
Distribution Services	4170000	Non-Regulated
Vegetation Services	4170000	Non-Regulated
Metering Services	4170000	Non-Regulated
Transformer Services	4170000	Non-Regulated
Material Solutions	4170000	Non-Regulated
Joint Trenching	4170000	Non-Regulated
Off System Power Marketing	4170000	Non-Regulated

Nonutility Property (Account 121)

Company: Florida Power Corporation
For the Year Ended December 31, 2003

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of nonutility property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the balance at the end of the year, for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other property nonutility property.

Description and Location	Balance at beginning of year	Purchases, Sales, Transfers, etc.	Balance at end of year
Previously Devoted to Public Service			
Land - Marion County - Florida	$ 135,191		$ 135,191
Structures - Pinellas County, Florida	177,011		177,011
Minor Items	531,940		531,940
Not Previously Devoted to Public Service			
Land - Volusia County, Florida	2,752,511		2,752,511
Equipment - Meters System (Florida)	3,394,922	589,970	3,984,892
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other Non-Utility Property	261,389	(26,614)	234,775
Totals	$ 8,633,157	$ 563,356	$ 9,196,513

Number of Electric Department Employees

Company: Florida Power Corporation
For the Year Ended December 31, 2003

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	**11/2/2003**
2. Total Regular Full-Time Employees	**4045**
3. Total Part-Time and Temporary Employees	**323**
4. Total Employees	**4368**

Details

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Florida Power Corporation
For the Year Ended December 31, 2003

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Account 426 - Miscellaneous Income Deductions	
Civic & Community Organizations	$ 416,295
Education Related Contributions	412,725
Health & Human Services Contributions	78,762
Miscellaneous Cultural Organizations	143,196
Other	287,278
Progress Energy Foundations	2,500,000
Subtotal Accounts 4261014, 426180T, 4261BUD	3,838,256
Investment in Company Owned Life Insurance	(1,691,237)
Subtotal Accounts 4262016, 4262041	(1,691,237)
Penalties	5,000
Subtotal Account 4263001	5,000
Certain Civic, Political & Related Activities	4,751,718
Subtotal Accounts 4264100, 4264200, 4264300	4,751,718
Other Deductions	652,958
Subtotal Account 4265001	652,958
Total Miscellaneous Income Deductions - Account 426	$ 7,556,695
Account 430 - Interest Expense	
Moneypool - Account 4301010 - Rate of 1.78% at 12/31/03	$ 2,001,066
Total Account 430	2,001,066
Account 431 - Other Interest Expense	
Commitment Fees	$ 800,795
Commercial Paper - zero balance at 12/31/03	227,166
Customer Deposits - Rate 6 to 7% per annum	7,410,353
Interest related to Projected Tax Deficiency on various audit issues - Rate 7%	(19,942,504)
Deferred Interest Expense - account 431XXXX	-
Total Account 431	$ (11,504,190)