THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

EI801-04-AR

Form 1 Approved
OMB No. 1902-0021
(Expires 6/30/2007)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. 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 these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Florida Power Corporation	End of 2004/Q4

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.

We have audited the balance sheet—regulatory basis of Progress Energy Florida, Inc. (the "Company") as of December 31, 2004, 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, 2004, included on pages 110 through 123 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 123.1, 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, 2004, and the results of its operations and its cash flows for the year ended December 31, 2004, 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

April 12, 2005

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

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 Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 141.400.

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).

Nonmajor means having in each of the three `previous calendar years, total annual sales of 10,000 megawatt hours or more

III. What and Where to Submit
(a) Submit Forms 1, 1-F and 3-Q electronically through the Form 1/3-Q Submission Software. Retain one copy of each report for your files.
(b) Respondents may submit the Corporate Officer Certification electronically, or file/mail an original signed Corporate Officer Certification to:

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

(c) 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 Form 1, 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 the address in III(c) above.

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, 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) be 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 158.10-158.12 for specific qualifications.)

Reference 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

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 address indicated at III (b). Use the following form 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 ED-12.2 Washington, DC 20426 (202).502-8371

IV. When to Submit:

Submit Form 1 according to the filing dates contained in section 18 CFR 141.1 of the Commission's regulations. Submit Form 1-F according to the filing dates contained in section 18 CFR 141.2 of the Commission's regulations. Submit Form 3-Q according to the filing dates contained in section 18 CFR 141.400 of the Commission's regulations.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 1 collection of information is estimated to average 1,144 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.public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 150 hours per response. Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Mr. Michael Miller, ED-30); 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 any 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 period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous 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 and 3.

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).

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 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.

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

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

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.
FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.
LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "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. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.
OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "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 OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.
SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.
NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.
OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service form. Describe the type of service in a footnote for each entry.
AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS
I. Commision 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.

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 ;he 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*.10

"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 field..."

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. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Florida Power Corporation	02 Year/Period of Report End of 2004/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(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 Accounting
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)* 12/31/2004

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Geoffrey S. Chatas	03 Signature Geoffrey S. Chatas	04 Date Signed *(Mo, Da, Yr)* 04/25/2005
02 Title Executive VP and CFO		

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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
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	Purchases and Sales of Ancillary Services	398	
54	Monthly Transmission System Peak Load	400	
55	Electric Energy Account	401	
56	Monthly Peaks and Output	401	
57	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
58	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	None
59	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	None
60	Generating Plant Statistics (Small Plants)	410-411	None
61	Transmission Line Statistics	422-423	
62	Transmission Lines Added During Year	424-425	
63	Substations	426-427	
	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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	President and CEO	H. William Habermeyer, Jr.	543,585
2			
3	Group President	William S. Orser	993,349
4			
5	Executive Vice President	William D. Johnson	983,442
6			
7	Executive Vice President	Peter M. Scott, III	906,725
8			
9	Executive Vice President and CFO	Geoffrey S. Chatas	758,296
10			
11			
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			
42			
43			
44			

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

Listed on Page 104 is the compensation information for the CEO of Florida Power Corporation and the four most highly compensated officers other than the CEO for the year ended December 31, 2004. 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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	Geoffrey S. Chatas, Executive Vice President	PO Box 1551, Raleigh, NC 27602
3	Fred N. Day, IV, Executive Vice President	PO Box 1551, Raleigh, NC 27602
4	H. William Habermeyer, Jr., President and CEO	100 Central Avenue, St. Petersburg, FL 33701
5	William D. Johnson, Executive Vice President	PO Box 1551, Raleigh, NC 27602
6	Robert B. McGehee, Chairman	PO Box 1551, Raleigh, NC 27602
7	William S. Orser, Group President	PO Box 1551, Raleigh, NC 27602
8	Peter M. Scott III, Executive Vice President	PO Box 1551, Raleigh, NC 27602
9		
10	Note: Florida Power Corporation Board does not have an	
11	Executive Committee.	
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		
42		
43		
44		
45		
46		
47		
48		

Schedule Page: 105 Line No.: 1 Column: a
Resigned from the Board effective April 26, 2004.

Schedule Page: 105 Line No.: 2 Column: a
Elected to the Board effective April 26, 2004.

Schedule Page: 105 Line No.: 6 Column: a
Named Chairman effective April 26, 2004.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

IMPORTANT CHANGES DURING THE QUARTER/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.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. CHANGES IN AND IMPORTANT ADDITIONS TO FRANCHISE RIGHTS

During the year ended December 31, 2004, three (3) new agreements were approved with municipalities with which the company had existing agreements. These agreements have a term of 30-years and do not contain purchase options.

One (1) new franchise was signed with the City of Apopka, where the previous agreement had expired. This agreement is a 30-year agreement with a purchase option exercisable at the end of the 30-year term.

One (1) new franchise was signed with the City of Ocala with whom the company did not have an existing agreement. The agreement has a 30-year term with no purchase option.

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.

2. ACQUISITION OF OWNERSHIP IN OTHER COMPANIES

None

3. PURCHASE OR SALE OF AN OPERATING UNIT OR SYSTEM

None

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) During the year ended December 31, 2004, Florida Power Corporation issued $6,423,984,194 in commercial paper and redeemed a total of $6,291,123,000. The average daily weighted yield during the period was 1.380366.

b) As of December 31, 2004, the Company's revolving credit facilities totaled $400 million, all of which supports it commercial paper borrowing. The Company has two credit agreements: (1) a 364-Day Credit Agreement, dated as of April 1, 2003, as amended and restated, for $200 million; and (2) a 3-Year Credit Agreement, dated as of April 1, 2003, for $200 million. During the fourth quarter 2004, the Company borrowed a net total of $55 million under its long-term credit facility, which remained outstanding as of December 31, 2004. In addition, the Company borrowed $170 million under its short-term credit facility, which remained outstanding as of December 31, 2004.

c) On July 1, 2004, Florida Power Corporation paid at maturity $40 million 6.69% Medium-Term Notes Series B with commercial paper proceeds and cash from operations.

Authorization of items under Note 6 relating to issuance of bonds, preferred stock and debentures was received from the Florida Public Service Commission under Order PSC-03-1439-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

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, 2004.

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

None

11. (Reserved)

12. IF CHANGES DURING YEAR APPEAR IN THE ANNUAL REPORT TO STOCKHOLDERS IN EVERY RESPECT, SUCH NOTES CAN BE INCLUDED

Not Applicable

13. DESCRIBE FULLY ANY CHANGES IN OFFICERS, DIRECTORS, MAJOR SECURITY HOLDERS AND VOTING POWERS OF THE REPONDENT

William Cavanaugh III, Chairman	Retired May 12, 2004
Geoffrey S. Chatas, Executive VP	Elected April 26, 2004
Robert B. McGehee, Chairman	Elected Chairman May 12, 2004

14. IF RESPONDENT PARTICIPATES IN A CASH MANAGEMENT PROGRAM AND ITS PROPRIETARY CAPITAL RATIO IS LESS THAN 30 PERCENT, DESCRIBE SIGNIFICANT EVENTS OR TRANSACTIONS CAUSING THE PROPRIETARY CAPITAL RATIO TO BE LESS THAN 30 PERCENT, AND EXTENT TO WHICH THE RESPONDENT HAS AMOUNTS LOANED OR MONEY ADVANCED TO ITS PARENT, SUBSIDIARY OR AFFILIATED COMPANIES THROUGH A CASH MANAGEMENT PROGRAM. ADDITIONALLY DESCRIBE PLANS TO REGAIN AT LEAST 30 PERCENT PROPRIETARY RATIO

Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	8,395,323,055	8,162,864,888
3	Construction Work in Progress (107)	200-201	419,736,394	291,653,170
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,815,059,449	8,454,518,058
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,187,956,959	4,026,292,251
6	Net Utility Plant (Enter Total of line 4 less 5)		4,627,102,490	4,428,225,807
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	415,230	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		103,060,264	103,037,800
10	Spent Nuclear Fuel (120.4)		0	111,517,438
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	58,232,497	145,446,991
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		45,242,997	69,108,247
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,672,345,487	4,497,334,054
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		19,254,493	9,196,513
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,961,499	2,284,760
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		357,724	203,603
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		497,704,806	466,111,154
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		2,400,444	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		511,755,968	473,226,510
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,973,321	8,475,582
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		1,308,073	659,150
40	Customer Accounts Receivable (142)		189,689,778	185,192,376
41	Other Accounts Receivable (143)		12,625,412	7,617,235
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,476,021	2,229,825
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		15,718,807	7,390,823
45	Fuel Stock (151)	227	103,298,488	90,516,921
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	156,388,226	167,409,657
49	Merchandise (155)	227	204,989	424,410
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	10,253,426	912,089

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	19,516,453	9,361,873
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		233,981,327	224,329,737
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		282,642	256,095
61	Accrued Utility Revenues (173)		65,582,761	58,686,140
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		2,400,444	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		2,400,444	0
67	Total Current and Accrued Assets (Lines 34 through 66)		817,347,682	759,002,263
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		21,406,295	24,534,022
70	Extraordinary Property Losses (182.1)	230	12,645,771	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	350,394,489	368,450,412
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	105
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	365,126,350	12,913,205
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		31,172,912	32,880,007
82	Accumulated Deferred Income Taxes (190)	234	167,278,404	133,953,304
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		948,024,221	572,831,055
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,949,473,358	6,302,393,882

Schedule Page: 110 Line No.: 2 Column:

Balance per the 12/31/03 filing was $8,157,601,890. Increase of $5,262,998 is due to a reclassification from Accum. Prov. for Depreciation on line 5.

Schedule Page: 110 Line No.: 3 Column:

Balance per 12/31/03 filing was $328,267,599. Decrease of $36,614,429 is due to a reclassification of $37,213,889 to Plant Materials and Operating Supplies on line 48 and a reclassification of $599,460 from Accum. Prov. for Depreciation on line 5.

Schedule Page: 110 Line No.: 5 Column:

Balance per 12/31/03 filing was $4,020,429,793. Increase of $5,862,458 is due to a reclassification to Utility Plant on line 2 in the amount of $5,262,998 and to Construction Work in Process on line 3 in the amount of $599,460.

Schedule Page: 110 Line No.: 48 Column:

Balance per the 12/31/03 filing was $130,195,768. Increase of $37,213,889 is due to a reclassification from Construction Work in Process on line 3.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Florida Power Corporation	(1) ☐ An Original (2) ☐ A Rresubmission	12/31/2004	end of 2004/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (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	726,881,210	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	1,239,735,201	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	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-69,995	-3,783,531
16	Total Proprietary Capital (lines 2 through 15)		2,354,479,546	2,172,335,523
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,570,865,000	1,570,865,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	391,800,002	379,500,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,111,251	3,865,412
24	Total Long-Term Debt (lines 18 through 23)		1,959,553,751	1,946,499,588
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		46,915,219	40,915,219
28	Accumulated Provision for Injuries and Damages (228.2)		13,023,633	15,880,703
29	Accumulated Provision for Pensions and Benefits (228.3)		161,692,198	155,650,203
30	Accumulated Miscellaneous Operating Provisions (228.4)		106,041,531	68,064,326
31	Accumulated Provision for Rate Refunds (229)		10,080,153	17,880,360
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		336,645,620	319,276,955
35	Total Other Noncurrent Liabilities (lines 26 through 34)		674,398,354	617,667,766
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		292,867,000	0
38	Accounts Payable (232)		250,521,404	152,433,782
39	Notes Payable to Associated Companies (233)		178,777,135	363,286,516
40	Accounts Payable to Associated Companies (234)		79,500,854	73,953,595
41	Customer Deposits (235)		135,499,493	126,764,870
42	Taxes Accrued (236)	262-263	38,585,326	26,131,233
43	Interest Accrued (237)		45,838,009	46,084,394
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Florida Power Corporation	(1) ☐ An Original (2) ☐ A Rresubmission	12/31/2004	end of 2004/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		11,230,317	9,233,983
48	Miscellaneous Current and Accrued Liabilities (242)		59,197,211	60,454,475
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		5,183,190	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,097,199,939	858,342,848
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	35,280,508	41,351,508
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	16,476,930	11,404,747
60	Other Regulatory Liabilities (254)	278	197,353,198	196,566,595
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	6,186,000	7,182,000
63	Accum. Deferred Income Taxes-Other Property (282)		435,312,618	402,111,000
64	Accum. Deferred Income Taxes-Other (283)		173,232,514	48,932,307
65	Total Deferred Credits (lines 56 through 64)		863,841,768	707,548,157
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,949,473,358	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) 12/31/2004	Year/Period of Report 2004/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 42 Column:

Balance per 12/31/03 filing was $30,152,914. Decrease of $4,021,681 is due to a reclassification to Interest Accrued on line 43.

Schedule Page: 112 Line No.: 43 Column:

Balance per 12/31/03 filing was $42,062,713. Increase of $4,021,681 is due to reclassification from Taxes Accrued on line 42.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

STATEMENT OF INCOME

1. Enter in column (e) operations for the reporting quarter and in column (f) the operations for the same three month period for the prior year.
2. Report in Column (g) year to date amounts for electric utility function; in column (i) the year to date amounts for gas utility, and in (k) the year to date amounts for the other utility function for the current quarter/year.
3. Report in Column (h) year to date amounts for electric utility function; in column (j) the year to date amounts for gas utility, and in (l) the year to date amounts for the other utility function for the previous quarter/year.
4. If additional columns are needed place them in a footnote.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,526,632,391	3,140,833,180		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,215,094,994	2,107,621,828		
5	Maintenance Expenses (402)	320-323	120,985,725	134,373,529		
6	Depreciation Expense (403)	336-337	263,999,924	243,276,489		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,494,018	1,491,608		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	16,809,016	17,162,225		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-411,716	-367,763		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-18,677,749	48,446,911		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		246,906,186	32,952,895		
13	(Less) Regulatory Credits (407.4)		206,665,301	209,125,853		
14	Taxes Other Than Income Taxes (408.1)	262-263	254,104,999	241,134,838		
15	Income Taxes - Federal (409.1)	262-263	68,215,864	160,594,108		
16	- Other (409.1)	262-263	10,030,248	27,833,613		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	386,371,645	83,576,000		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	270,269,511	110,498,000		
19	Investment Tax Credit Adj. - Net (411.4)	266	-6,071,000	-6,071,000		
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)		-1,000			
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		17,368,665	16,472,558		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,099,287,007	2,788,873,986		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		427,345,384	351,959,194		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

-

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
3,526,632,391	3,140,833,180					2
						3
2,215,094,994	2,107,621,828					4
120,985,725	134,373,529					5
263,999,924	243,276,489					6
1,494,018	1,491,608					7
16,809,016	17,162,225					8
-411,716	-367,763					9
-18,677,749	48,446,911					10
						11
246,906,186	32,952,895					12
206,665,301	209,125,853					13
254,104,999	241,134,838					14
68,215,864	160,594,108					15
10,030,248	27,833,613					16
386,371,645	83,576,000					17
270,269,511	110,498,000					18
-6,071,000	-6,071,000					19
						20
						21
-1,000						22
						23
17,368,665	16,472,558					24
3,099,287,007	2,788,873,986					25
427,345,384	351,959,194					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		427,345,384	351,959,194		
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)		13,681,312	5,424,708		
34	(Less) Expenses of Nonutility Operations (417.1)		10,556,255	7,245,818		
35	Nonoperating Rental Income (418)		-298,577	-212,998		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		2,588,760	1,751,970		
38	Allowance for Other Funds Used During Construction (419.1)		7,100,379	11,587,391		
39	Miscellaneous Nonoperating Income (421)		1,639,090	3,688,383		
40	Gain on Disposition of Property (421.1)		1,450,090			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		15,604,799	14,993,636		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			161,752		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	4,269,120	3,838,256		
46	Life Insurance (426.2)		-1,462,738	-1,691,237		
47	Penalties (426.3)		97,191	5,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,221,840	4,751,718		
49	Other Deductions (426.5)		781,011	652,958		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,906,424	7,718,447		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	170,280	151,821		
53	Income Taxes-Federal (409.2)	262-263	-13,002,964	-15,135,928		
54	Income Taxes-Other (409.2)	262-263	-981,567	-1,098,688		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277		7,573,000		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-13,814,251	-8,509,795		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		21,512,626	15,784,984		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		105,570,677	101,279,778		
63	Amort. of Debt Disc. and Expense (428)		3,186,615	2,892,916		
64	Amortization of Loss on Reaquired Debt (428.1)		2,113,865	1,985,749		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	1,289,565	2,001,086		
68	Other Interest Expense (431)	340	5,277,422	-11,487,835		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,462,518	5,650,620		
70	Net Interest Charges (Total of lines 62 thru 69)		113,975,626	91,021,074		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		334,882,384	276,723,104		
72	Extraordinary Items					
73	Extraordinary Income (434)			19,631,385		
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)			19,631,385		
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)			19,631,385		
78	Net Income (Total of line 71 and 77)		334,882,384	296,354,489		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. 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.
9. 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)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,061,364,677	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)		334,882,384	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	Preferred Stock Dividends Declared		-1,511,860	(1,511,860)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,511,860	(1,511,860)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends Declared		-155,000,000	(203,272,876)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-155,000,000	(203,272,876)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,239,735,201	1,061,364,677
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. 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.
9. 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)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
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 (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,239,735,201	1,061,364,677
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(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 in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	334,882,384	296,354,489
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	265,632,639	245,122,881
5	Amortization of Limited and Electric Plant, Non-fuel, Load Mgmt	36,930,764	35,135,314
6	Amortization of Debt premium, expense and loss on reacquisition	2,542,010	2,548,134
7	Other: (Gain) Loss on Sale of Assets, Bad Debt expense	4,147,490	4,973,775
8	Deferred Income Taxes (Net)	116,102,135	-19,349,002
9	Investment Tax Credit Adjustment (Net)	-6,071,000	-6,071,000
10	Net (Increase) Decrease in Receivables	-29,069,086	28,696,040
11	Net (Increase) Decrease in Inventory	-26,671,813	-32,669,561
12	Net (Increase) Decrease in Allowances Inventory	-9,341,337	325,794
13	Net Increase (Decrease) in Payables and Accrued Expenses	47,896,994	28,084,602
14	Net (Increase) Decrease in Other Regulatory Assets	27,365,398	-145,335,362
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,064,212	-9,516,455
16	(Less) Allowance for Other Funds Used During Construction	7,100,379	11,587,392
17	(Less) Undistributed Earnings from Subsidiary Companies	-40,184	
18	Other (provide details in footnote): Change in Current Assets	1,650,630	-221,374
19	Change in Pension	-11,302,220	2,355,570
20	Change in Other, net	-213,196,107	29,625,405
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	533,374,474	448,471,858
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-488,148,771	-520,617,545
27	Gross Additions to Nuclear Fuel	-417,550	-50,890,321
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-2,431,960	-1,303,727
30	(Less) Allowance for Other Funds Used During Construction	3,462,518	5,650,620
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-494,460,799	-578,462,213
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	82,660	624,896
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-210,000	-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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(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 in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
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): Company owned life insurance	-1,500,000	
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-496,088,139	-577,847,317
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	56,053,296	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)	292,867,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	348,920,296	1,061,365,611
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-42,699,998	-476,216,434
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Dividends to Parent	-155,000,000	-203,272,876
77	Dividends on Preferred Stock	-1,511,859	-1,511,859
78	Net Decrease in Short-Term Debt (c)		-258,149,000
79	Other: Intercompany notes	-184,497,035	
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)	-34,788,596	122,215,442
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,497,739	-7,160,017
87			
88	Cash and Cash Equivalents at Beginning of Period	8,475,582	15,635,597
89			
90	Cash and Cash Equivalents at End of period	10,973,321	8,475,580

Schedule Page: 120 Line No.: 5 Column:

Balance per 12/31/03 filing was $27,211,988. Change of $7,923,326 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 7 Column:

Balance per 12/31/03 filing was $161,752. Change of $4,812,023 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 10 Column:

Balance per 12/31/03 filing was $33,607,193. Change of -$4,911,153 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 11 Column:

Balance per 12/31/03 filing was $4,544,328. Change of -$37,213,889 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 13 Column:

Balance per 12/31/03 filing was $12,654,505. Change of $15,430,097 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 15 Column:

Balance per 12/31/03 filing was -$1,593,129. Change of -$7,923,326 is due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 20 Column:

Balance per 12/31/03 filing was $29,526,277. Change of $99,128 due to reclassifications to conform with 2004 presentation.

Schedule Page: 120 Line No.: 26 Column:

Balance per 12/31/03 filing was -$542,401,338. Change of $21,783,793 due to reclassifications to conform with 2004 presentation.

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.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, 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 the presentation of (1) cost of removal assets and liabilities, (2) storm costs, (3) deferred income taxes, (4) SFAS No. 109 regulatory assets and liabilities, (5) long term portions of deferred fuel, (6) current portions of long-term debt, (7) preferred stock, (8) extraordinary items, (9) prepaid emission allowances, (10) the reclassification of the rate refund accrual (as a result of the rate case) from a long-term liability to a current liability, (11) current portions of regulatory liabilities and (12) current and long term portions of derivatives.

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 (net of amount capitalized) and income taxes (net of refunds) for the year ended 2004 were $118 million and $57 million, respectively.

FLORIDA PROGRESS CORPORATION AND FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC. NOTES TO INTERIM 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.

The Financial Statements of the Company and its subsidiaries include the accounts of their majority-owned and controlled subsidiaries. Noncontrolling interests in the subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which the Company does not have control, but has the ability to exercise influence over operating and financial policies (generally 20% – 50% ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 19). These equity method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has equity method investments of approximately $11 million and $12 million, respectively.

Certain investments in debt and equity securities that have readily determinable market values, and for which the Company does not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants. The fair value of these trust funds was $463 million and $433 million at December 31, 2004 and 2003, respectively.

Other investments are stated principally at cost. These cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2004 and 2003, the Company has approximately $12 million and $13 million, respectively, of cost method investments.

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 2003 and 2002 have been reclassified to conform to the 2004 presentation.

C. Consolidation of Variable Interest Entities

Florida Progress and PEF consolidate all voting interest entities in which they own a majority voting interest and all variable interest entities for which they are the primary beneficiary in accordance with FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" (FIN No. 46R). A subsidiary of Florida Progress is the primary beneficiary of and consolidates Colona Synfuel Limited Partnership LLLP (Colona), a synthetic fuel production facility that qualifies for federal tax credits under Section 29 of the Internal Revenue Code. As of December 31, 2004, Colona's total assets were $15 million. None of Florida Progress' consolidated assets are collateral for Colona's obligations.

Florida Progress and PEF have interests in several variable interest entities for which they are not the primary beneficiary. These arrangements include investments in approximately five limited partnerships, limited liability corporations and venture capital funds. The aggregate maximum loss exposure at December 31, 2004, that Florida Progress could be required to record in its consolidated income statement as a result of these arrangements totals approximately $13 million. The aggregate maximum loss exposure at December 31, 2004, that PEF could be required to record in its income statement as a result of these arrangements totals approximately $6 million. The creditors of these variable interest entities do not have recourse to the general credit of Florida Progress or PEF in excess of the aggregate maximum loss exposure.

D. 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

PEF 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 generally recognized at the time products are shipped or as services are rendered. Revenues from sales of synthetic fuel and coal are recognized as products are shipped and title passes. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Lease revenue for dedicated transport and data services is generally billed in advance on a fixed rate basis and recognized over the period the services are provided. 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. These deferred fuel costs are recognized in revenue and fuel expenses as they are billable to customers.

EXCISE TAXES

PEF 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, 2004, 2003 and 2002, gross receipts tax and franchise taxes of approximately $151 million, $136 million and $132 million, respectively, are included in electric operating revenues and taxes other than on income on the Statements of Income.

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. Except for the allocation of this Progress Energy tax benefit, 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 as AMT credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) in the Consolidated Statements of Income (See Note 14).

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	2004	2003	2002
Net income, as reported	**$ 474**	$ 447	$ 235
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**3**	3	3
Pro forma net income	**$ 471**	$ 444	$ 232

(in millions) Progress Energy Florida	2004	2003	2002
Net income, as reported	**$ 335**	$ 297	$ 325
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	**2**	2	2
Pro forma net income	**$ 333**	$ 295	$ 323

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. PEF capitalizes all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal, disposal and decommissioning costs that do not represent ARO's under SFAS No. 143 "Accounting for Asset Retirement Obligations," (SFAS No. 143) are charged to regulatory liabilities.

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 system 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.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, the Company adopted the guidance in SFAS No. 143 to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which the Company has a legal obligation are recorded as liabilities 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.

The adoption of this statement had no impact on the income of PEF, as the effects were offset by the establishment of a regulatory liability pursuant to SFAS No. 71 , "Accounting for the Effects of Certain Types of Regulation" (See Note 8A). The Florida Public Service Commission (FPSC) issued an order to authorize deferral of all prospective effects related to SFAS No. 143 as a regulatory asset or liability (See Note 8A).

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 6A). Pursuant to its rate setting authority, the FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In PEF's retail jurisdiction, 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.

INVENTORY

The Company accounts for inventory using the average-cost method. Inventories are valued at the lower of cost or market.

REGULATORY ASSETS AND LIABILITIES

PEF's regulated operations are subject to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," 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 8A).

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 cost of renewals and betterments are capitalized. The cost of repairs and maintenance is charged to expense as incurred. For properties other than natural gas and oil properties, depreciation is computed on a straight-line basis over the estimated useful lives as indicated in Note 6B. 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 oil and gas properties. Under the full-cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas 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 on a country-by-country basis over the life of the Company's proved reserves. Accordingly, all property acquisition, exploration and development costs of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized as incurred including internal costs directly attributable to such activities. Related interest expense incurred during property development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred. In accordance with Regulation 210.4-10 of Regulation S-X, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless certain significance tests are met.

GOODWILL AND INTANGIBLE ASSETS

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. 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 are amortized over the terms of the debt issues. 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 (See Note 8A).

DERIVATIVES

The Company accounts for derivative instruments in accordance with 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, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. The Company generally designates derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, the Company will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met (See Note 16).

ENVIRONMENTAL

As discussed in Note 20, the Company accrues environmental remediation liabilities when the criteria for SFAS No. 5, "Accounting for Contingencies," have been met. Environmental 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. Environmental expenditures that have future economic benefits are capitalized in accordance with the Company's asset capitalization policy.

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."

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 (See Note 10). 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.

Under the full-cost method of accounting for oil and gas 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. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. 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 2004, 2003 or 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, except for any transactions that must be credited directly to equity in accordance with the provisions of Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. IMPACT OF NEW ACCOUNTING STANDARDS

FASB STAFF POSITION 106-2, "ACCOUNTING AND DISCLOSURE REQUIREMENTS RELATED TO THE MEDICARE PRESCRIPTION DRUG IMPROVEMENT AND MODERNIZATION ACT OF 2003"

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. In accordance with guidance issued by the FASB in FASB Staff Position 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" (FASB Staff Position 106-1), the Company elected to defer accounting for the effects of the Medicare Act due to uncertainties regarding the effects of the implementation of the Medicare Act and the accounting for certain provisions of the Medicare Act. In May 2004, the FASB issued definitive accounting guidance for the Medicare Act in FASB Staff Position 106-2, which was effective for the Company in the third quarter of 2004. FASB Staff Position 106-2 results in the recognition of lower other postretirement benefits (OPEB) costs to reflect prescription drug-related federal subsidies to be received under the Medicare Act. The Company's and PEF's accumulated postretirement benefit obligations as of January 1, 2004 were reduced by approximately $36 million and $35 million, respectively, by the impact of the Medicare Act, and the Company's and PEF's 2004 net periodic cost was lower by approximately $5 million due to the Medicare Act.

STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 123 (REVISED 2004), "SHARE-BASED PAYMENT" (SFAS NO. 123R)

In December 2004, the FASB Issued SFAS No. 123R, which revises SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) and supersedes Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." The key requirement of SFAS No. 123R is that the cost of share-based awards to employees will be measured based on an award's fair value at the grant date, with such cost to be amortized over the appropriate service period. Previously, entities could elect to continue accounting for such awards at their grant date intrinsic value under APB Opinion No. 25, and the Company made that election. The intrinsic value method resulted in the Company and PEF recording no compensation expense for stock options granted to employees (See Note 11B).

SFAS No. 123R will be effective for the Company on July 1, 2005. The Company intends to implement the standard using the required modified prospective method. Under that method, the Company will record compensation expense under SFAS No. 123R for all awards it grants after July 1, 2005, and it will record compensation expense (as previous awards continue to vest) for the unvested portion of previously granted awards that remain outstanding at July 1, 2005. In 2004, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued. The Company and PEF expect to record less than $1 million of pre-tax expense for stock options in 2005.

PROPOSED FASB INTERPRETATION OF SFAS 109, "ACCOUNTING FOR INCOME TAXES"

In July 2004, the FASB stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes," that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

3. HURRICANE-RELATED COSTS

Hurricanes Charley, Frances, Ivan and Jeanne struck significant portions of the PEF's service territory during the third quarter of 2004. As of December 31, 2004, restoration costs of PEF's systems from hurricane-related damage was estimated at $385 million, of which $47 million was charged to capital expenditures, and $338 million was charged to the storm damage reserve pursuant to a regulatory order.

In accordance with a regulatory order, PEF accrues $6 million annually to a storm damage reserve and is allowed to defer losses in excess of the accumulated reserve for major storms. Under the order, the storm reserve is charged with operation and maintenance expenses related to storm restoration and with capital expenditures related to storm restoration that are in excess of expenditures assuming normal operating conditions. As of December 31, 2004, $291 million of hurricane restoration costs in excess of the previously recorded storm reserve of $47 million had been classified as a regulatory asset recognizing the probable recoverability of these costs. On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from retail ratepayers over a two-year period. Storm reserve costs of $13 million were attributable to wholesale customers. PEF has received approval from the FERC to amortize these costs consistent with recovery of such amounts in wholesale rates. PEF continues to review the restoration cost invoices received. Given that not all invoices have been received as of December 31, 2004, PEF will update its petition with the FPSC upon receipt and audit of all actual charges incurred. Hearings on PEF's petition for recovery of $252 million of storm costs filed with the FPSC are scheduled to begin on March 30, 2005.

On November 17, 2004, the Citizens of the State of Florida, by and through Harold McLean, Public Counsel, and the Florida Industrial Power Users Group (FIPUG), (collectively, Joint Movants), filed a Motion to Dismiss PEF's petition to recover the $252 million in storm costs. On November 24, 2004, PEF responded in opposition to the motion, which was also the FPSC staff's position in its recommendation to the Commission on December 21, 2004 that it should deny the Motion to Dismiss. On January 4, 2005, the Commission ruled in favor of PEF and denied joint Movant's Motion to Dismiss.

PEF's January 2005 notice to the FPSC of its intent to file for an increase in its base rates effective January 1, 2006, anticipates the need to replenish the depleted storm reserve balance and adjust the annual $6 million accrual in light of recent storm history to restore the reserve to an adequate level over a reasonable time period (See Note 8B).

4. DIVESTITURES

A. Sale of Natural Gas Assets

In December 2004, the Company sold certain gas-producing properties and related assets owned by Winchester Production Company, Ltd., an indirectly wholly owned subsidiary of Progress Fuels Corporation (Progress Fuels), which is included in the Fuels segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of the Company's remaining oil and gas properties. The pre-tax gain has been included in (gain)/loss on the sale of assets in the Consolidated Statements of Income.

B. Divestiture of Synthetic Fuel Partnership Interests

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, one of its synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gain from the sales will be recognized on a cost recovery basis. The Company's book value of the interests sold totaled approximately $3 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted.

C. 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. 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 Consolidated Statements of Income (See Note 10). In March 2003, the Company signed a letter of intent to sell the majority of Railcar Ltd. assets to The Andersons, Inc., and the transaction closed in February 2004. Proceeds from the sale were approximately $82 million before transaction costs and taxes of approximately $13 million. In July 2004, the Company sold the remaining assets classified as held for sale to a third-party for net proceeds of $6 million. The assets of Railcar Ltd. were grouped as assets held for sale and were included in other current assets on the Consolidated Balance Sheets at December 31, 2003, at approximately $75 million, which reflected the Company's estimates of the fair value expected to be realized from the sale of these assets less costs to sell.

D. 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 (Progress Fuels), which is included in the Fuels segment. Net proceeds were approximately $97 million and 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.

E. Inland Marine Transportation Divestiture

In July 2001, Progress Energy announced the disposition of the Inland Marine Transportation segment of the Company, which was operated by MEMCO Barge Line, Inc. Inland Marine provided transportation of coal, agricultural and other dry-bulk commodities as well as fleet management services. Progress Energy entered into a contract to sell MEMCO Barge Line, Inc., to AEP Resources, Inc., a wholly-owned subsidiary of American Electric Power. In November 2001, the Company completed the sale of the Inland Marine Transportation segment. The net income of these operations is reported in the Company's Consolidated Statements of Income as discontinued operations.

The net gain on disposal of discontinued operations in the Company's Consolidated Statements of 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 (See Note 20).

5. 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 (PT LLC), a subsidiary of PTC. Subsequently, the stock of Caronet was sold to an affiliate of Odyssey for $2 million in cash and Caronet became 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, PT LLC. Odyssey holds a combined 45% ownership interest in PT LLC through EPIK and Caronet. The accounts of PT LLC have been included in the Company's Financial Statements since the transaction date. The minority interest is included in other liabilities and deferred credits in the 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. No gain or loss was recognized on the transaction. The EPIK purchase price was initially allocated as follows: property and equipment – $27 million; other current assets – $9 million; current liabilities – $21 million, and goodwill – $7 million. During 2004, PT LLC developed a restructuring plan to exit certain leasing arrangements of EPIK and finalized its valuation of acquired assets and liabilities. Management considered a number of factors, including valuations and appraisals, when making these determinations. Based on the results of these activities, the preliminary purchase price allocation for EPIK was revised as follows at December 31, 2004: property and equipment – $36 million; other current assets – $7 million; intangible assets – $1 million; current liabilities – $18 million; and exit costs – $4 million. The exit costs consist primarily of lease termination penalties and noncancellable lease payments made after certain leased properties are vacated. The pro forma results of operations reflecting the acquisition would not be materially different then the reported results of operation for 2003 or 2002.

B. Acquisition of Natural Gas Reserves

During 2003, Progress Fuels 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. The pro forma results of operations reflecting the acquisition would not be materially different from the reported results of operations for the years ended December 31, 2003 and 2002.

C. Westchester Acquisition

In April 2002, Progress Fuels, a subsidiary of Progress Energy, acquired 100% of Westchester Gas Company. During 2004 the name of the company was changed to Winchester Energy Company, Ltd. (Winchester Energy). 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-mile 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 then 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 in intangible assets relates to customer contracts (See Note 9).

The acquisition has been accounted for using the purchase method of accounting and, accordingly, the results of operations for Winchester have been included in the Company's 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 year ended December 31, 2002.

6. 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)	**2004**	2003
Production plant (7-33 years)	**$ 3,818**	$ 3,826
Transmission plant (30-75 years)	**1,070**	1,012
Distribution plant (12-50 years)	**3,047**	2,894
General plant and other (8-75 years)	**452**	423
Utility plant in service	**$ 8,387**	$ 8,155

Substantially all of the electric utility plant is pledged as collateral for the first mortgage bonds of PEF (See Note 12).

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 system 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 2004, 2003 and 2002.

Depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.3% in 2004, 2003 and 2002. The depreciation provisions related to utility plant were $188 million, $172 million and $162 million in 2004, 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 6D) and regulatory approved expenses (See Note 8 and 20).

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, for the years ended December 31, 2004, 2003 and 2002 were $34 million, $31 million and $32 million, respectively. These amounts are charged to fuel used in electric generation in the Statements of Income.

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)	**2004**	2003
Equipment (3 – 25 years)	**$ 418**	$ 283
Land and mineral rights	**95**	80
Buildings and plants (5 – 40 years)	**106**	99
Oil and gas properties (units-of-production) (See Note 4A)	**336**	412
Telecommunications equipment (5 – 20 years)	**80**	63
Rail equipment (3 – 20 years) (See Note 4C)	**35**	131
Marine equipment (3 – 35 years)	**87**	83
Computers, office equipment and software (3 – 10 years)	**36**	33
Construction work in progress	**18**	18
Accumulated depreciation	**(435)**	(361)
Diversified business property, net	**$ 776**	$ 841

Diversified business depreciation expense was $112 million, $92 million and $66 million for the years ended December 31, 2004, 2003 and 2002, respectively. The synthetic fuel facilities are being depreciated through 2007 when the Section 29 tax credits will expire. Oil and gas depreciation, depletion, and amortization (DD&A) expense was $41 million, $33 million, and $11 million for the years ended December 31, 2004, 2003, and 2002, respectively. DD&A rates per Mcfe were $1.34, $1.31 and $0.92 for the respective years. Oil and gas properties included costs of $55 million at December 2004 which were excluded from capitalized costs being amortized. This includes $48 million in costs related to acquisitions and capitalized interest on probable reserves of $7 million.

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**
2004				
Crystal River Unit No. 3	**91.78%**	**$ 889**	**$ 443**	**$ 9**
Intercession City Unit P-11	**66.67%**	**22**	**7**	**8**
2003				
Crystal River Unit No. 3	91.78%	$ 875	$ 442	$ 46
Intercession City Unit P-11	66.67%	22	6	6

D. Asset Retirement Obligations

The asset retirement costs related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $36 million and $37 million for regulated operations at December 31, 2004 and 2003, respectively. 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 $463 million at December 31, 2004 and $433 million at December 31, 2003. Net unrealized gains on the nuclear decommissioning trust fund were included in regulatory liabilities.

PEF's expense recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset removal obligations, which are included in depreciation and amortization expense, were $77 million, $72 million and $68 million in 2004, 2003 and 2002, respectively.

PEF recognizes removal, non-nuclear decommissioning and dismantlement costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, 2004, such costs consist of removal costs of $1,005 million, decommissioning costs for nonirradiated areas at nuclear facilities of $61 million and amounts previously collected for dismantlement of fossil generation plants of $144 million. At December 31, 2003, such costs consist of removal costs of $945 million, decommissioning costs for nonirradiated areas at nuclear facilities of $62 million and amounts previously collected for dismantlement of fossil generation plants of $143 million.

PEF 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 PEF. 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 is not estimable for such easements, as PEF intends to utilize these properties indefinitely. In the event PEF decides to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

The Company's nonregulated AROs relate to coal mine operations, synthetic fuel operations and gas production of Progress Fuels Corporation. The related asset retirement costs, net of accumulated depreciation, totaled $10 million and $5 million at December 31, 2004 and 2003, respectively.

The following table shows the changes to the asset retirement obligations. Additions relate primarily to additional reclamation obligations at coal mine operations of Progress Fuels.

(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**
Additions	**–**	**6**
Accretion expense	**18**	**2**
Deductions	**–**	**(7)**
Asset retirement obligations as of December 31, 2004	**$ 337**	**$ 21**

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 for the year ended December 31, 2003. 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.

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 71 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 $6.5 million with respect to the primary coverage, $5.2 million with respect to the decontamination, decommissioning and excess property coverage, and $5.5 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 $10.76 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 could possibly approve revisions to the Price Anderson Act during 2005, 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.

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 3 and 8A).

7. CURRENT ASSETS

RECEIVABLES

At December 31, receivables were comprised of the following:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Trade accounts receivable	**$ 438**	$ 410	**$ 195**	$ 187
Unbilled accounts receivable	**93**	135	**66**	59
Notes receivable	**97**	62	–	–
Other receivables	**12**	15	**7**	6
Unbilled other receivables	**28**	11	–	–
Allowance for doubtful accounts receivable	**(19)**	(15)	**(2)**	(2)
Total receivables	**$ 649**	$ 618	**$ 266**	$ 250

Income tax receivables and interest income receivables are not included in this classification. These amounts are in prepayments and other current assets on the Consolidated Balance Sheets.

INVENTORY

At December 31, inventory was comprised of the following:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Fuel for production	**$ 103**	$ 90	**$ 103**	$ 90
Inventory for sale	**228**	167	–	–
Materials and supplies	**187**	192	**176**	178
Total inventory	**$ 518**	$ 449	**$ 279**	$ 268

8. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As a regulated entity, PEF is subject to the provisions of SFAS No. 71. 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)	**2004**	2003
Deferred fuel cost - current (Note 8B)	**$ 89**	$ 204
Deferred fuel cost – long-term (Note 8B)	**79**	–
Storm deferral (Note 3)	**291**	–
Income taxes recoverable through future rates (Note 14)	**49**	42
Loss on reacquired debt (Note 1D)	**31**	33
Other	**74**	51
Total long-term regulatory assets	**524**	126

Deferred energy conservation cost - current	**(8)**	(7)
Non-ARO cost of removal (Note 6D)	**(1,210)**	(1,150)
Deferred impact of ARO (Note 1D)	**(26)**	(8)
Net nuclear decommissioning trust unrealized gains (Note 6D)	**(99)**	(105)
Storm reserve (Note 3)	**–**	(41)
Other	**(27)**	(11)
Total long-term regulatory liabilities	**(1,362)**	(1,315)
Net regulatory assets (liabilities)	**$ (757)**	$ (992)

Except for portions of deferred fuel and deferred storm costs, 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.

B. Retail Rate Matters

On November 9, 2004, the FPSC approved PEF's under-recovered fuel costs of $156 million for 2004, of which PEF plans to defer $79 million until 2006 to mitigate the impact on customers resulting from the need to also recover hurricane-related costs. Therefore, $79 million of deferred fuel cost has been classified as a long-term asset. As of December 31, 2004, PEF was under-recovered in fuel costs by $168 million. The additional $12 million over and above the $156 million approved by the FPSC will be included in PEF's 2005 fuel filing.

On June 29, 2004, the FPSC approved a Stipulation and Settlement Agreement, executed on April 29, 2004, by PEF, the Office of Public Counsel and the Florida Industrial Power Users Group. The stipulation and settlement resolved the issue pending before the FPSC regarding the costs PEF will be allowed to recover through its Fuel and Purchased Power Cost Recovery clause in 2004 and beyond for waterborne coal deliveries by the Company's affiliated coal supplier, Progress Fuels Corporation. The settlement sets fixed per ton prices based on point of origin for all waterborne coal deliveries in 2004, and establishes a market-based pricing methodology for determining recoverable waterborne coal transportation costs through a competitive solicitation process or market price proxies in 2005 and thereafter. The settlement reduces the amount that PEF will charge to the Fuel and Purchased Power Cost Recovery clause for waterborne transportation by $11 million beginning in 2004.

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost. Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating). The estimated total in-service cost of Hines Unit 4 is $286 million, and the unit is planned for commercial operation in December 2007. If the actual cost is less than the estimate, customers will receive the benefit of such cost under runs. Any costs that exceed this estimate will not be recoverable absent extraordinary circumstances as found by the FPSC in subsequent proceedings.

PEF RATE CASE SETTLEMENT

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 2004, 2003 and 2002 were $1.370 billion, $1.333 billion and $1.296 billion, respectively, and will increase $37 million in 2005. 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 caps for 2004, 2003 and 2002 were $1.430 billion, $1.393 billion and $1.356 billion, respectively, and will increase $37 million in 2005. Any amounts above the retail base revenue caps will be refunded 100% to customers. At December 31, 2004, $9 million has been accrued and will be refunded to retail customers by March 2005. The 2003 revenue sharing amount was $18 million, and was refunded to customers by April 30, 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. In 2004, PEF recovered $36 million through this clause related to Hines Unit 2.

In addition, 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. No accelerated depreciation expense was recorded during 2004 and 2003. In addition, PEF is authorized, at its discretion, to accelerate the amortization of certain regulatory assets over the term of the Agreement.

Under the terms of the Agreement, PEF agreed to continue the implementation of its four-year Commitment to Excellence Reliability Plan and expected to achieve a 20% improvement in its annual System Average Interruption Duration Index by no later than 2004. If this improvement level was not achieved for calendar years 2004 or 2005, PEF would have provided 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. PEF achieved this improvement level in 2004.

In January 2005, in anticipation of the expiration of its Stipulation and Settlement approved by the FPSC in 2002 to conclude PEF's then-pending rate case, PEF notified the FPSC that it intends to request an increase in its base rates, effective January 1, 2006. In its notice, PEF requested the FPSC to approve calendar year 2006 as the projected test period for setting new base rates. The request for increased base rates is based on the fact that PEF has faced significant cost increases over the past decade and expects its operational costs to continue to increase. These costs include the costs associated with completion of the Hines 3 generation facility, extraordinary hurricane damage costs including capital costs which are not expected to be directly recoverable, the need to replenish the depleted storm reserve and the expected infrastructure investment necessary to meet high customer expectations, coupled with the demands placed on PEF as a result of strong customer growth. On February 7, 2005, the FPSC acknowledged receipt of PEF's notice and authorized minimum filing requirements and testimony to be filed May 1, 2005.

C. Regional Transmission Organizations and Standard Market Design

In 2000, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000 regarding regional transmission organizations (RTOs). This Order set minimum characteristics and functions that RTOs must meet, including independent transmission service. In July 2002, the 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 have materially altered the manner in which transmission and generation services are provided and paid for. In April 2003, the FERC released a White Paper on the Wholesale Market Platform. The White Paper provided an overview of what the FERC intended to include in a final rule in the SMD NOPR docket. The White Paper retained 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. The FERC has not yet issued a final rule on SMD NOPR. The Company cannot predict the outcome of these matters or the effect that they may have on the GridFlorida proceedings currently ongoing before the FERC.

The Florida Public Service Commission (FPSC) ruled in December 2001 that the formation of GridFlorida by the three major investor-owned utilities in Florida, including PEF, was prudent but ordered changes in the structure and market design of the proposed organization. In September 2002, the FPSC set a hearing for market design issues; this order was appealed to the Florida Supreme Court by the consumer advocate of the state of Florida. In June 2003, the Florida Supreme Court dismissed the appeal without prejudice. In September 2003, the FERC held a Joint Technical Conference with the FPSC to consider issues related to formation of an RTO for peninsular Florida. In December 2003, the FPSC ordered further state proceedings and established a collaborative workshop process to be conducted during 2004. In June 2004, the workshop process was abated pending completion of a cost-benefit study currently scheduled to be presented at a FPSC workshop on May 25, 2005, with subsequent action by the FPSC to be thereafter determined.

PEF has $4 million invested in GridFlorida related to startup costs at December 31, 2004. PEF expects to recover these startup costs in conjunction with the GridFlorida original structure or in conjunction with any alternate combined transmission structure that emerges.

D. Energy Delivery Capitalization Practice

PEF has reviewed its capitalization policy for its Energy Delivery business unit. That review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, PEF should revise the way that it estimates the amount of capital costs associated with such work. PEF has implemented such changes effective January 1, 2005, which include more detailed classification of outage and emergency work and result in more precise estimation and a process of retesting accounting estimates on an annual basis. As a result of the changes in accounting estimates for the outage and emergency work and indirect costs, a lesser proportion of PEF's costs will be capitalized on a going forward basis. PEF estimates that the impact in 2005 will be that approximately $30 million of costs that would have been capitalized under the previous policies will be expensed. Pursuant to SFAS No. 71, PEF has informed the state regulators having jurisdiction over them of this change and that the new estimation process will be implemented effective January 1, 2005. The Company has also requested a method change from the IRS.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

The Company accounts for goodwill and other intangible assets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The changes in the carrying amount of goodwill, by reportable segment, are as follows:

(in millions)	Energy and Related Services	Other	Total
Balance as of January 1, 2003	$ 11	$ –	$ 11
Divestitures	(1)	–	(1)
Acquisition	–	7	7
Balance as of December 31, 2003	**$ 10**	**$ 7**	**$ 17**
Impairment loss	**(8)**	–	**(8)**
Purchase accounting adjustment	–	**(7)**	**(7)**
Balance as of December 31, 2004	**$ 2**	**$ –**	**$ 2**

In connection with a review of strategic alternatives regarding the Fuels' coal mining business, the Company performed an impairment test of the goodwill of the coal mining business in the fourth quarter of 2004. As a result of the impairment test, the Company recorded an impairment loss of $8 million to write off all of the goodwill of the coal mining business. The Company used a probability-weighted discounted cash flow analysis to perform the assessment.

In December 2003, $7 million in goodwill was acquired based on a preliminary purchase price allocation as part of the Progress Telecommunications Corporation partial acquisition of EPIK and was reported in the Other segment. As discussed in Note 5, the Company revised the preliminary EPIK purchase price allocation as of September 2004, and the $7 million of goodwill was reallocated to certain tangible assets acquired based on the results of valuations and appraisals.

The Company has $10 million and $9 million of net amortizable intangible assets at December 31, 2004 and 2003, respectively. The Company's intangibles are primarily acquired customer contracts that are amortized over their respective lives. Amortization expense recorded on intangible assets for the years ended December 31, 2004 and 2003, and estimated annual amortization expense for intangible assets for 2004 through 2008 are not material to the results of operations. PEF has no intangible assets at December 31, 2004 or 2003.

10. 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 4C). 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.

11. EQUITY

A. Common and Preferred Stock

Common stock at December 31, 2004 and 2003 consisted of the following

(in millions except share data)	**2004**	2003
Florida Progress		
Common stock without par value, 250,000,000 shares authorized; 98,616,658 shares outstanding in 2004 and 2003	**$ 1,712**	**$ 1,699**
Progress Energy Florida		
Common stock without par value, 60,000,000 shares authorized; 100 shares outstanding in 2004 and 2003	**$ 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 $13 million, $168 million and $220 million during 2004, 2003 and 2002, respectively. The Company paid dividends to Progress Energy of $340 million, $301 million and $303 million during 2004, 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, 2004 and 2003 consisted of the following (in millions, except share data and par value):

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 $102.00)		**8**
Total Preferred Stock of PEF	**$**	**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 nonbargaining unit employees and certain part-time nonbargaining 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 $5 million, $4 million and $2 million for the years ended December 31, 2004, 2003 and 2002, respectively. Matching and incentive costs totaled approximately $7 million, $11 million and $10 million for the years ended December 31, 2004, 2003 and 2002, respectively. PEF's matching and incentive cost which was and will be met with shares released from the suspense account totaled approximately $5 million, $4 million and $2 million for the year ended December 31, 2004, 2003 and 2002, respectively. Matching and incentive costs totaled approximately $7 million, $10 million and $9 million for the years ended December 31, 2004, 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, 2004, 2003 and 2002 approximately 28 thousand, 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 and approximately 0.5 million and 0.4 million options, respectively, were granted in 2002. No stock options were granted to officers and employees of Florida Progress and PEF in 2004. The Company expects to begin expensing stock options on July 1, 2005 by adopting new FASB guidance on accounting for stock-based compensation that was issued (See Note 2). In 2004, however, Progress Energy made the decision to cease granting stock options and intends to replace that compensation program with other programs. Therefore, the amount of stock option expense expected to be recorded in 2005 is below the amount that would have been recorded if the stock option program had continued.

The pro forma information presented in Note 1 regarding net income and earnings per share is required by SFAS No. 148. Under this statement, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The pro forma amounts presented in Note 1 have been determined as if the Company had accounted for its employee stock options under SFAS No. 123.

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 $2 million, $9 million and $5 million in 2004, 2003 and 2002, respectively. The total amount expensed by PEF for other stock-based compensation under these plans was $2 million, $7 million and $4 million in 2004, 2003 and 2002, respectively.

C. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss for Florida Progress and PEF at December 31, 2004 and 2003 are as follows:

	Florida Progress		Progress Energy Florida	
(in millions)	**2004**	2003	**2004**	2003
Loss on cash flow hedges	**$ (5)**	$ (9)	**$ –**	$ –
Minimum pension liability adjustments	**(7)**	(9)	**–**	(4)
Foreign currency translation and other	**5**	1	**–**	–
Total accumulated other comprehensive loss	**$ (7)**	$ (17)	**$ –**	$ (4)

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit

At December 31, the Company's (including PEF's) long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2004):

(in millions)	Rate	2004	2003
Progress Energy Florida, Inc.			
First mortgage bonds, maturing 2008-2033	5.60%	**1,330**	1,330
Pollution control obligations, maturing 2018-2027	1.67%	**241**	241
Medium-term notes, maturing 2005-2028	6.76%	**337**	379
Draws on revolving credit agreement, expiring 2006	2.95%	**55**	–
Unamortized premium and discount, net		**(3)**	(3)
		1,960	1,947
Florida Progress Funding Corporation (See Note 17)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2006-2008	6.84%	**140**	165
Unsecured note with parent, maturing 2011	6.45%	**500**	500
Miscellaneous notes		**1**	1
		641	666
Current portion of long-term debt		**(49)**	(68)
Total long-term debt		**$ 2,861**	$ 2,854

In February 2005, PEF used proceeds from money pool borrowings to pay off $55 million of RCA loans and in January 2005, PEF used proceeds from the issuance of commercial paper to pay off $170 million of RCA loans.

At December 31, 2004, PEF had committed lines of credit which are used to support its commercial paper borrowings. The 3-year credit facility is included in long-term debt. The 364-day credit facility is included in short-term obligations and had $170 million of outstanding borrowings at December 31, 2004, at an interest rate of 3.13%. No amount was outstanding under the committed lines of credit at December 31, 2003. 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	Outstanding	Available
364-Day (expiring 3/29/05)	$ 200	$ 170	$ 30
3-Year (expiring 4/01/06)	200	55	145
Less: amounts reserved(a)			(123)
Total credit facilities	$ 400	$ 225	$ 52

(a) To the extent amounts are reserved for commercial paper outstanding, they are not available for additional borrowings.

At December 31, 2004, PEF had $123 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, 2004 was 2.80%. At December 31, 2003, PEF had no outstanding commercial paper and other short-term debt classified as short-term obligations.

The combined aggregate maturities of Florida Progress long-term debt for 2005 through 2008 are approximately, in millions, $49, $163, $124 and $127, respectively. PEF's aggregate maturities of long-term debt for 2005 through 2008 are approximately, in millions, $48, $103, $89 and $82, respectively. There are no long-term debt maturities in 2009 for PEF or Florida Progress.

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, 2004, PEF's total debt to total capital ratio was 50.8%.

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, 2004, this ratio was 7.93 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 (MAC) in the borrower's financial condition.

CROSS-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 MAC 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. At December 31, 2004, none of PEF's retained earnings were restricted.

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, 2004, 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, 2004, PEF's common stock equity was approximately 54.4% of total capitalization.

C. Secured Obligations

PEF's first mortgage bonds are secured by its mortgage indenture. 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, 2004, PEF had approximately $1.571 billion 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

See Note 17 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

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 16.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

At December 31, 2004 and 2003, there were miscellaneous investments, consisting primarily of investments in company-owned life insurance and other benefit plan assets, with carrying amounts of approximately $73 million and $66 million, respectively, included in miscellaneous other property and investments. At PEF, these investments had carrying amounts of $34 million and $33 million at December 31, 2004 and 2003, respectively. 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 $2,910 million and $2,922 million at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $3,121 million and $3,105 million at December 31, 2004 and 2003, respectively. The carrying amount of PEF's long-term debt, including current maturities, was $1,960 million and $1,947 million at December 31, 2004 and 2003, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $2,080 million and $2,061 million at December 31, 2004 and 2003, respectively.

External trust funds have been established to fund certain costs of nuclear decommissioning (See Note 6D). These nuclear decommissioning trust funds are invested in stocks, bonds and cash equivalents. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments.

14. INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when there are differences between book and tax carrying amounts 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. 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 utility pursuant to rate orders.

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

Florida Progress	**2004**	2003
Current portion of deferred income tax asset		
Unbilled revenue	**$ 35**	$ 18
Other	**33**	42
Net current portion of deferred income tax asset	**$ 68**	$ 60
Noncurrent deferred income tax asset (liability):		
Accumulated depreciation and property cost differences	**$ (400)**	$ (359)
Investments	**49**	(17)
Supplemental executive retirement plans	**19**	19
Other post-employment benefits (OPEB)	**65**	64
Other pension plans	**(89)**	(85)
Goodwill	**34**	46
Deferred storm costs	**(113)**	–
Storm damage reserve	–	16
Premium on reacquired debt	**(12)**	(13)
State NOL carry forward	**23**	28
Federal and state income tax credit carry forward	**494**	437
Miscellaneous other temporary differences, net	**57**	25
Valuation allowance	**(27)**	(29)
Total noncurrent deferred income tax asset	**100**	132
Less amount included in other assets and deferred debits	**161**	172
Net noncurrent deferred income tax liability	**$ (61)**	$ (40)

Progress Energy Florida	2004	2003
Current portion of deferred income tax asset		
Unbilled revenue	$ 35	$ 18
Other	7	21
Net current portion of deferred income tax asset	$ 42	$ 39
Noncurrent deferred income tax asset (liability):		
Accumulated depreciation and property cost differences	$ (389)	$ (368)
Other post-employment benefits (OPEB)	63	62
Other pension plans	(89)	(85)
Deferred storm costs	(113)	–
Storm damage reserve	–	16
Miscellaneous other temporary differences, net	39	17
Total noncurrent deferred income tax liability	$ (489)	$ (358)

The Company's total deferred income tax liabilities were $997 million and $824 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $1,165 million and $1,016 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Consolidated Balance Sheets at December 31, 2004 and 2003 include $2 and $7 million, respectively, related to contingent tax liabilities on which the Company accrues interest that would be payable with the related tax amount in future years.

PEF's total deferred income tax liabilities were $620 million and $476 million at December 31, 2004 and 2003, respectively. Total deferred income tax assets were $173 million and $157 million at December 31, 2004 and 2003, respectively. Total noncurrent income tax liabilities on the Balance Sheets at December 31, 2004 and 2003 include none and $5 million, respectively, related to contingent tax liabilities on which the company accrues interest that would be payable with the related tax amount in future years.

The Company's federal income tax credit carry forward at December 31, 2004 consists of $484 million of alternative minimum tax credit with an indefinite carry forward period and $9 million of general business credit with a carry forward period that will begin to expire in 2022. The Company's alternative minimum tax credit carry forward at December 31, 2004 includes $3 million that would be limited if a change in ownership were to occur with respect to certain indirect wholly owned subsidiary companies.

As of December 31, 2004, the Company had a state net operating loss carry forward of $2 million that will begin to expire in 2007.

The Company decreased its valuation allowance during 2004 by $2 million and 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 decreased its 2004 beginning-of-the-year valuation allowance by $8 million for a change in circumstances related to net operating losses. 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.

The Company establishes accruals for certain tax contingencies when, despite the belief that the Company's tax return positions are fully supported, the Company believes that certain positions may be challenged and that it is probable the Company's positions may not be fully sustained. The Company is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2004 and 2003, respectively, the Company had recorded $60 million and $56 million of tax contingency reserves, excluding accrued interest and penalties, which are included in current Taxes Accrued on the Consolidated Balance Sheets. At December 31, 2004 and 2003, PEF had recorded $7 million of tax contingency reserves, excluding accrued interest and penalties, which are included in other current liabilities on the Balance Sheets. Considering all tax contingency reserves, the Company does not expect the resolution of these matters to have a material impact on its financial position or result of operations. All tax contingency reserves relate to capitalization and basis issues and do not relate to any potential disallowances of tax credits from synthetic fuel production (See Note 21E).

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

Florida Progress	**2004**	2003	2002
Effective income tax rate	**13.3%**	(32.6)%	(304.8)%
State income taxes, net of federal benefit	**(6.1)**	(2.5)	(10.3)
AFUDC amortization	**(0.5)**	(0.7)	(4.1)
Federal tax credits	**24.4**	63.5	311.3
Investment tax credit amortization	**1.2**	1.8	11.3
Progress Energy tax allocation benefit	**2.7**	3.8	35.2
Other differences, net	**—**	1.7	(3.6)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

Progress Energy Florida	**2004**	2003	2002
Effective income tax rate	**34.2%**	33.1%	33.6%
State income taxes, net of federal benefit	**(3.5)**	(3.5)	(3.4)
Investment tax credit amortization	**1.2**	1.4	1.3
Progress Energy tax allocation benefit	**2.5**	2.7	3.8
Other differences, net	**0.6**	1.3	(0.3)
Statutory federal income tax rate	**35.0%**	35.0%	35.0%

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

Florida Progress	**2004**	2003	2002
Current - federal	**$ 46**	$ 6	$ 43
State	**31**	18	23
Deferred - federal	**(16)**	(123)	(220)
State	**15**	(5)	(13)
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense (benefit)	**$ 70**	$ (110)	$ (173)

Progress Energy Florida	**2004**	2003	2002
Current - federal	**$ 55**	$ 145	$ 172
State	**9**	27	29
Deferred - federal	**98**	(16)	(29)
State	**18**	(3)	(3)
Investment tax credit	**(6)**	(6)	(6)
Total income tax expense (benefit)	**$ 174**	$ 147	$ 163

Florida Progress and each of its wholly-owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 1D). The Company's intercompany tax payable was approximately $72 million and $17 million at December 31, 2004 and 2003, respectively. Progress Energy Florida's intercompany tax payable was approximately $21 million and $16 million at December 31, 2004 and 2003, respectively.

Florida Progress, through its subsidiaries, is a majority owner in two entities and a minority owner in four entities that owns facilities that produce synthetic fuel as defined under the Internal Revenue Code (Code). The production and sale of the synthetic fuel from these facilities qualifies for tax credits under Section 29 if certain requirements are satisfied (See Note 21E).

15. 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)	**2004**	2003	2002	**2004**	2003	2002
Service cost	$ **22**	$ 21	$ 19	$ **4**	$ 5	$ 5
Interest cost	**48**	46	44	**14**	16	15
Expected return on plan assets	**(77)**	(62)	(76)	**(1)**	(1)	(1)
Net amortization	**1**	3	(7)	**5**	5	4
Net cost/(benefit) recognized by Florida Progress	$ **(6)**	$ 8	$ (20)	$ **22**	$ 25	$ 23
Net cost/(benefit) recognized by PEF	$ **(8)**	$ 5	$ (22)	$ **21**	$ 24	$ 22

The net periodic cost for other postretirement benefits decreased during 2004 due to the implementation of FASB Staff Position 106-2 (See Note 2).

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)	**2004**	2003	**2004**	2003
Obligation at January 1	$ **780**	$ 714	$ **224**	$ 236
Service cost	**22**	21	**4**	5
Interest cost	**48**	46	**14**	15
Plan amendments	**2**	–	–	–
Benefit payments	**(42)**	(41)	**(17)**	(15)
Actuarial loss (gain)	**39**	40	**15**	(17)
Obligation at December 31	**849**	780	**240**	224
Fair value of plan assets at December 31	**919**	849	**20**	18
Funded status	**70**	69	**(220)**	(206)
Unrecognized transition obligation	–	–	**28**	31
Unrecognized prior service cost (benefit)	**(14)**	(18)	**6**	7
Unrecognized net actuarial loss	**117**	111	**30**	15
Minimum pension liability adjustment	**(14)**	(11)	–	–
Prepaid (accrued) cost at December 31, net – Florida Progress	$ **159**	$ 151	$ **(156)**	$ (153)
Prepaid (accrued) cost at December 31, net – PEF	$ **192**	$ 183	$ **(150)**	$ (148)

The 2003 OPEB obligation information above has been restated due to the implementation of FASB Staff Position 106-2 (See Note 2).

The Florida Progress net prepaid pension cost of $159 million and $151 million at December 31, 2004 and 2003, respectively, is included in the Company's Consolidated Balance Sheets as prepaid pension cost of $238 million and $223 million, respectively, which is included in other assets and deferred debits, and accrued benefit cost of $79 million and $72 million, respectively, which is included in accrued pension and other benefits. The PEF net prepaid pension cost of $192 million and $183 million at December 31, 2004 and 2003, respectively, is included in the Balance Sheets as prepaid pension cost of $234 million and $220 million, respectively, and accrued benefit cost of $42 million and $37 million, respectively, which is included in accrued pension and other benefits. For Florida Progress, the defined benefit pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations totaling $80 million and $74 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $77 million and $73 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 $41 million and $38 million at December 31, 2004 and 2003, respectively. Those plans had accumulated benefit obligations totaling $39 million and $37 million, respectively, and no plan assets. For Florida Progress, the total accumulated benefit obligation for pension plans was $797 million and $736 million at December 31, 2004 and 2003, respectively. For PEF, the total accumulated benefit obligation for pension plans was $718 million and $659 million at December 31, 2004 and 2003, respectively. Accrued other postretirement benefit cost is included in accrued pension and other benefits in the respective Balance Sheets of Florida Progress and PEF.

Florida Progress and PEF recorded a minimum pension liability adjustment of $14 million and $7 million, respectively, at December 31, 2004, with a corresponding charge of $7 million to a regulatory asset and, for Florida Progress, a pre-tax charge of $7 million to accumulate other comprehensive loss, a component of common stock equity. 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.

Reconciliations of the fair value of plan assets are:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2004**	2003	**2004**	2003
Fair value of plan assets January 1	**$ 849**	$ 687	**$ 18**	$ 16
Actual return on plan assets	**108**	199	**1**	1
Benefit payments	**(42)**	(41)	**(18)**	(15)
Employer contributions	**4**	4	**19**	16
Fair value of plan assets at December 31	**$ 919**	$ 849	**$ 20**	$ 18

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 2004 and 2003 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	2005	**2004**	2003	2005	**2004**	2003
Equity – domestic	48%	**47%**	49%	–	–	–
Equity – international	15%	**21%**	22%	–	–	–
Debt – domestic	12%	**9%**	11%	100%	**100%**	100%
Debt – international	10%	**11%**	11%	–	–	–
Other	15%	**12%**	7%	–	–	–
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 2005, the Company expects to make no required contributions to pension plan assets and $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $43, $45, $47, $51, $55 and $337, respectively. The expected benefit payments for the OPEB plan for 2005 through 2009 and in total for 2010-2014, in millions, are approximately $17, $19, $20, $21, $22 and $126, 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 Company expects to begin receiving prescription drug-related federal subsidies in 2006 (See Note 2), and the expected subsidies for 2006 through 2009 and in total for 2010-2014, in millions, are approximately $2, $2, $2, $2 and $14, respectively. PEF represents a significant majority of the Company's expected benefit payments and expected subsidies to be received. The expected benefit payments above do not include the potential effects of a 2005 voluntary early retirement program (see Note 22).

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

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Discount rate	**5.90%**	6.30%	**5.90%**	6.30%
Rate of increase in future compensation				
Bargaining	**3.50%**	3.50%	–	–
Supplementary plans	**5.25%**	5.00%	–	–
Initial medical cost trend rate for pre-Medicare benefits	–	–	**7.25%**	7.25%
Initial medical cost trend rate for post-Medicare benefits	–	–	**7.25%**	7.25%
Ultimate medical cost trend rate	–	–	**5.00%**	5.25%
Year ultimate medical cost trend rate is achieved	–	–	**2008**	2009

The Company's primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in Emerging Issues Task Force 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. 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		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.30%**	6.60%	7.50%	**6.30%**	6.60%	7.50%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	–	–	–
Nonbargaining	–	4.00%	4.00%	–	–	–
Supplementary plan	**5.00%**	4.00%	4.00%	–	–	–
Expected long-term rate of return on plan assets	**9.25%**	9.25%	9.25%	**5.00%**	5.00%	5.00%

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 9.0% and 9.5%. The Company has chosen to use an expected long-term rate of 9.25%. 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 2004 would increase by $1 million, and the OPEB obligation at December 31, 2004, would increase by $13 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 2004 would decrease by $1 million and the OPEB obligation at December 31, 2004, would decrease by $12 million.

16. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

Under its risk management policy, the Company and PEF 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 and PEF minimize 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 or PEF.

A. Commodity Derivatives

GENERAL

Most of the Company's and PEF'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.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity forward contracts, may be entered into 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 2004, 2003 or 2002, and the Company did not have material outstanding positions in such contracts at December 31, 2004 or 2003.

In 2004, PEF entered into derivative instruments related to its exposure to price fluctuations on fuel oil purchases. At December 31, 2004, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits and a $5 million short-term derivative liability position included in other current liabilities. These instruments receive regulatory accounting treatment. Gains are recorded in regulatory liabilities and losses are recorded in regulatory assets.

CASH FLOW HEDGES

The Company's subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas for the Company's forecasted sales. In the normal course of business, Progress Fuels through an affiliate, Progress Ventures, Inc. (PVI), enters natural gas cash flow hedging instruments, which PVI offsets with third party transactions. Progress Fuels accounts for such contracts as if it were transacted with a third party and records the contract using mark-to-market or accrual accounting, as applicable. At December 31, 2004, 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, 2004 and 2003 was a $9 million and a $14 million liability position, respectively. The ineffective portion of commodity cash flow hedges was not material in 2004 and 2003. At December 31, 2004, there were $5 million of after-tax deferred losses in accumulated other comprehensive income (OCI). The entire amount is expected to be reclassified to earnings during the next 12 months as the hedged transactions occur. As part of the divestiture of Winchester Production Company, Ltd. assets in 2004, $7 million of after-tax deferred losses were reclassified into earnings due to discontinuance of the related cash flow hedges (See Note 4A). Due to the volatility of the commodities markets, the value in OCI is subject to change prior to its reclassification into earnings.

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

The Company and PEF manage its interest rate exposure in part by maintaining its variable-rate and fixed rate-exposures within defined limits. In addition, the Company and PEF also enter 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 and PEF use 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. The Company and PEF held no interest rate cash flow hedges at December 31, 2004 or 2003. At December 31, 2004, an immaterial amount of after-tax deferred losses in OCI, related to previously terminated hedges at PEF, is expected to be reclassified to earnings during the next 12 months as the hedged interest payments occur.

The Company and PEF use fair value hedging strategies to manage its exposure to fixed interest rates on long-term debt. At December 31, 2004 and 2003, the Company and PEF 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.

17. RELATED PARTY TRANSACTIONS

The Parent's subsidiaries provide and receive services, at cost, to and from the Company and its subsidiaries, in accordance with agreements approved by the U.S. Securities and Exchange Commission (SEC) pursuant to Section 13(b) of the PUHCA. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, constructions management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs which cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Consolidated Balance Sheets.

Progress Energy Service Company, LLC (PESC) provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2004, 2003 and 2002 to Florida Progress amounted to $199 million, $190 million and $173 million, respectively, and services provided to PEF were $165 million, $153 million and $161 million, respectively. Based on a standard review by the Office of Public Utility Regulation within the SEC the method for allocating certain PESC governance costs changed and retroactive reallocations for 2002 and 2001 charges were recorded in 2003. The net after-tax impact of the reallocation on 2003 was an increase in expenses of $5 million at Florida Progress and a reduction of expenses at PEF by $1 million. PEF and an affiliated utility also provide and receive services at cost. Services received by PEF during 2004, 2003 and 2002 amounted to $52 million, $35 million and $72 million, respectively. Services provided by PEF during 2004, 2003 and 2002 amounted to $16 million, $7 million and $16 million, respectively.

Progress Fuels sells coal to PEF for insignificant profits. These intercompany revenues and expenses are eliminated in consolidations; however, in accordance with SFAS No. 71 profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, of $331 million, $346 million and $329 million for the years ended December 31, 2004, 2003 and 2002, respectively, are included in fuel used in electric generation on Florida Progress' Consolidated and PEF's Statements of Income.

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 1.72%, 1.47% and 2.18% at December 31, 2004, 2003 and 2002, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. Net interest expense related to money pool borrowings was $7 million for 2004 and $5 million for Florida Progress for 2003 and 2002. PEF recorded insignificant interest expense related to the money pool for the three years presented.

As a part of normal business, Progress Energy and certain subsidiaries enter into various agreements providing financial or performance assurances to third parties. 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. As of December 31, 2004 Progress Energy and certain subsidiaries issued guarantees of $140 million supporting obligations under coal brokering operations and other agreements of subsidiaries. Progress Energy and certain subsidiaries also purchased $33 million of surety bonds and authorized the issuance of standby letters of credit by financial institutions of $40 million. Florida Progress has fully guaranteed the medium term notes outstanding for Progress Capital, a wholly owned subsidiary of Florida Progress. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheets.

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, 2004 and 2003, the Company has a note receivable of $28 million and $37 million from PVI that has been recorded as a reduction to equity for financial reporting purposes. Payments included insignificant amounts of interest for the three years presented.

PVI enters into derivative transactions on behalf of Progress Fuels, which are discussed further with the derivatives transactions (See Note 16A). PVI recorded $33 million, $28 million and $9 million of realized and unrealized gains for these derivative transactions in 2004, 2003 and 2002, respectively.

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 2004, 2003 and 2002 was $134 million, $182 million and $197 million, respectively.

During 2003, in order to more effectively utilize cash resources, Progress Fuels and the two PVI synthetic fuel operations began to participate in a money pool with cash management functions provided by Progress Fuels. Amounts payable to the money pool of $61 million and $34 million are included in notes payable to affiliated companies on the Consolidated Balance Sheets. Interest related to the money pool was insignificant for the three years presented.

A Progress Fuels subsidiary sells coal feedstock to an equity investment. The amount of revenue during 2004, 2003 and 2002 was $150 million, $117 million and $101 million, respectively.

Long-term debt, affiliate on the Florida Progress' Consolidated Balance Sheet consists of $500 million for Progress Fuels' unsecured note with Parent and $309 million of debt to an affiliated trust (See Note 12A). Progress Fuels recorded interest expense related to the unsecured note with Parent of $32 million for 2004 and 2003. The annual interest expense to the affiliated trust is $21 million and is reflected in the Consolidated Statements of Income.

Florida Progress Funding Corporation (Funding Corp.) $309 million 7.10% Junior Subordinated Deferrable Interest Notes (Subordinated Notes) are due to FPC Capital I (the Trust) (See Note 12A). The Trust was established for the sole purpose of issuing $300 million Preferred Securities and using the proceeds thereof to purchase from Funding Corp. its Subordinated Notes. The Company has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, the Company 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 the Company of the Trust's obligations under the Preferred Securities. The Subordinated Notes and the Notes Guarantee are the sole assets of the Trust. The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest. 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.

The Company and each of its wholly owned subsidiaries have entered into a Tax Agreement with Progress Energy (See Note 14).

18. 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 and eliminations. 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 2004 includes a gain on the sale of certain gas properties and assets of $56 million ($31 million after-tax) and a long-lived asset impairment on goodwill at Diamond May of $8 million before and after tax included in the Energy and Related Services segment. 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 2004, 2003 and 2002 is summarized below.

(in millions)	Utility	Energy and Related Services	Rail Svc.	Other	Consolidated
Year Ended December 31, 2004					
Unaffiliated revenues	**$ 3,525**	**$ 1,223**	**$ 1,130**	**$ 57**	**$ 5,935**
Intersegment revenues	–	**331**	**1**	**(332)**	–
Total revenues	**3,525**	**1,554**	**1,131**	**(275)**	**5,935**
Depreciation and amortization	**281**	**80**	**21**	**11**	**393**
Total interest charges, net	**114**	**20**	**27**	**19**	**180**
Gain on sale of assets	–	**54**	–	–	**54**
Impairment of goodwill and long-lived assets	–	**8**	–	–	**8**
Income tax expense (benefit)	**174**	**(106)**	**15**	**(13)**	**70**
Income (loss) from continuing operations	**333**	**137**	**16**	**(12)**	**474**
Total segment assets	**7,924**	**855**	**596**	**311**	**9,686**
Capital and investment expenditures	**482**	**157**	**40**	**6**	**685**
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 goodwill and long-lived assets	–	15	–	–	15
Income tax expense (benefit)	147	(246)	2	(13)	(110)
Income (loss) from continuing operations	295	166	(1)	(17)	443
Total segment assets	7,280	977	586	350	9,193
Capital and investment expenditures	526	310	103	11	950
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 goodwill and long-lived assets	–	–	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	535	121	8	42	706

Geographic Data

	U.S.	Canada	Mexico	Consolidated
2004				
Consolidated revenues	**$ 5,807**	**$ 112**	**$ 16**	**$ 5,935**
2003				
Consolidated revenues	$ 4,891	$ 103	$ 14	$ 5,008
2002				
Consolidated revenues	$ 4,393	$ 93	$ 14	$ 4,500

19. 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 for fiscal years 2004, 2003 and 2002 are as follows:

(in millions)	**2004**	2003	2002
Other income			
Nonregulated energy and delivery services income	**17**	14	17
AFUDC equity	**7**	12	2
Other	**3**	1	4
Total other income – Progress Energy Florida	**$ 27**	$ 27	$ 23
Other income – Florida Progress	**13**	5	6
Total other income – Florida Progress	**$ 40**	$ 32	$ 29
Other expense			
Nonregulated energy and delivery services expenses	**$ 11**	$ 11	$ 15
Donations	**8**	9	10
Other	**3**	–	5
Total other expense – Progress Energy Florida	**$ 22**	$ 20	$ 30
Loss from equity investments	**12**	15	14
Other expense – Florida Progress	**5**	5	5
Total other expense – Florida Progress	**$ 39**	$ 40	$ 49
Other, net	**$ 1**	$ (8)	$ (20)

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.

20. ENVIRONMENTAL MATTERS

The Company and PEF are 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

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. The Company and PEF are 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. The Company and PEF are also currently in the process of assessing potential costs and exposures at other environmentally impaired sites. For all sites the assessments are developed and analyzed, the Company and PEF will accrue costs for the sites to the extent the costs are probable and can be reasonably estimated.

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, through PEF, has some connection. In this regard, PEF and other potentially responsible parties (PRPs), 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).

The Florida Legislature passed risk-based corrective action (RBCA, known as Global RBCA) legislation in the 2003 regular session. Risk-based corrective action generally means that the corrective action prescribed for contaminated sites can correlate to the level of human health risk imposed by the contamination at the property. The Global RBCA law expands the use of the risk-based corrective action to all contaminated sites in the state that are not currently in one of the state's waste cleanup programs. The FDEP has developed the rules required by the RBCA statute, holding meetings with interested stakeholders and hosting public workshops. The rules have the potential for making future cleanups in Florida more costly to complete. The Global RBCA rule was adopted at the February 2, 2005 Environmental Review Commission hearing. The effective date of the Global RBCA rule is expected to be announced in April 2005. The Company and PEF are in the process of assessing the impact of this matter.

The Company and PEF have 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 and PEF cannot predict the outcome of this matter.

PEF

At December 31, 2004 and 2003, PEF's accruals for probable and estimable costs related to various environmental sites, which are included in other liabilities and deferred credits and are expected to be paid out over many years, were:

(in millions)	**2004**	2003
Remediation of distribution and substation transformers	**$ 27**	$ 12
MGP and other sites	**18**	6
Total accrual for environmental sites	**$ 45**	$ 18

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the FDEP, PEF is in the process of examining distribution transformer sites and substation sites for potential equipment integrity issues that could result in the need for mineral oil impacted soil remediation. Through 2004 PEF has reviewed a number of distribution transformer sites and substation sites. PEF expects to have completed its review of distribution transformer sites by the end of 2007 and has completed the review of substation sites in 2004. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC clause. In 2004, PEF accrued an additional $19 million, due to identification of additional sites requiring remediation, and spent approximately $4 million related to the remediation of transformers. PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC.

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation costs. In 2004, PEF received approximately $12 million in insurance claim settlement proceeds and recorded a related accrual for associated environmental expenses. The proceeds are restricted for use in addressing costs associated with environmental liabilities. Expenditures for the year were less than $1 million.

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 PRPs. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet advanced to the stage where a reasonable estimate of the remediation costs can be made, at this time PEF is unable to provide an estimate of its obligation to remediate these sites beyond what is currently accrued. As more activity occurs at these sites, PEF will assess the need to adjust the accruals. It is anticipated that sufficient information will become available in 2005 to make a reasonable estimate of PEF's obligation for one of the MGP sites.

FLORIDA PROGRESS CORPORATION

In 2001, FPC established a $10 million accrual to address indemnities and retained an environmental liability associated with the sale of its Inland Marine Transportation business. In 2003, the accrual was reduced to $4 million based on a change in estimate. During 2004, expenditures related to this liability were not material to the Company's financial condition. As of December 31, 2004, the remaining accrual balance was approximately $3 million and is included in other liabilities and deferred credits. FPC measures its liability for this site based on estimable and probable remediation scenarios.

Certain historical sites are being addressed voluntarily by FPC. An immaterial accrual has been established to address investigation expenses related to these sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

RAIL

Rail Services is voluntarily addressing certain historical waste sites. At this time, the Company cannot determine the total costs that may be incurred in connection with these sites.

AIR QUALITY

Congress is considering legislation that would require reductions in air emissions of NOx, SO_2, 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 and PEF's consolidated financial position or results of operations. However, the Company and PEF 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 changes at those facilities were subject to New Source Review requirements or New Source Performance Standards under the Clean Air Act. The Company was asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. 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 by these unaffiliated utilities, in excess of $1.0 billion. 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 and PEF cannot predict the outcome of this matter.

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. In July 2004, the EPA announced it will reconsider certain issues arising from the final routine equipment replacement rule. The comment period closed on August 30, 2004. The Company and PEF cannot predict the outcome of this matter.

In 1997, the EPA's Mercury Study Report and Utility Report to Congress concluded that mercury is not a risk to the average person in America 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 alternative control plans that would limit mercury emissions from coal-fired power plants. The final rule was released on March 15, 2005. The EPA's rule establishes a mercury cap and trade program for coal-fired power plants that requires limits to be met in two phases, in 2010 and 2018. The Company and PEF are reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the mercury rule's requirements. Compliance plans and the cost to comply with the rule will be determined once the Company and PEF complete their review.

In conjunction with the proposed mercury rule, the EPA proposed a 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. As proposed, the rule may require the company to install additional pollution controls on its residual oil-fired units, resulting in significant capital expenditures. PEF has eight units that are affected, and they currently do not have pollution controls in place that would meet the proposed requirements of the nickel rule. The EPA expects to finalize the nickel rule in March 2005. Compliance costs will be determined following promulgation of the rule.

In December 2003, the EPA released its proposed Interstate Air Quality Rule, currently referred to as the Clean Air Interstate Rule (CAIR). The final rule was released on March 10, 2005. The EPA's rule requires 28 states and the District of Columbia, including Florida, to reduce NOx and SO_2 emissions in order to attain preset state NOx and SO_2 emissions levels. The Company and PEF are reviewing the final rule. Installation of additional air quality controls is likely to be needed to meet the CAIR requirements. Compliance plans and the cost to comply with the rule, will be determined once the Company and PEF complete the review of the final rule.

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 at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on PEF in the immediate and extended future.

After many years of litigation and settlement negotiations the EPA adopted regulations in February 2004 to implement Section 316(b) of the Clean Water Act. These regulations became effective September 7, 2004. The purpose of these regulations is to minimize adverse environmental impacts caused by cooling water intake structures and intake systems. Over the next several years these regulations will impact the larger base load generation facilities and may require the facilities to mitigate the effects to aquatic organisms by constructing intake modifications or undertaking other restorative activities. PEF currently estimates that from 2005 through 2009 the range of its expenditures to meet the Section 316(b) requirements of the Clean Water Act will be $65 million to $85 million.

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. In 2004, Russia ratified the Protocol, and the treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration has stated it favors voluntary programs. A number of carbon dioxide emissions control proposals have been advanced in Congress. 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 consolidated financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. The Company favors the voluntary program approach recommended by the administration and continually evaluates options for the reduction, avoidance and sequestration of greenhouse gases. However, the Company and PEF cannot predict the outcome of this matter.

Progress Energy has announced its plan to issue a report on the Progress Energy's activities associated with current and future environmental requirements. The report will include a discussion of the environmental requirements that the Company and PEF currently face and expect to face in the future, as well as an assessment of potential mandatory constraints on carbon dioxide emissions. The report will be issued by March 31, 2006.

21. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2004, the following table reflects the Company's contractual cash obligations and other commercial commitments in the respective periods in which they are due.

(in millions)	2005	2006	2007	2008	2009	Thereafter
Fuel	$ 1,571	$ 1,023	$ 270	$ 102	$ 116	$ 684
Purchased power	334	342	354	364	331	4,086
Construction obligations	51	–	–	–	–	–
Other purchase obligations	44	38	36	22	20	93
Total	$ 2,000	$ 1,403	$ 660	$ 488	$ 467	$ 4,863

FUEL AND PURCHASED POWER

The Company has entered into various long-term contracts for oil, gas and coal. The Company's payments under these commitments were $1,620 million, $1,157 million and $891 million in 2004, 2003 and 2002, respectively. PEF's payments totaled $372 million, $208 million and $94 million in 2004, 2003 and 2002, respectively. The Company's estimated annual payments for firm commitments of fuel purchases and transportation costs under these contracts make up the fuel line in the previous table. PEF's future payments under these contracts at December 31, 2004 are $375 million, $258 million, $125 million, $102 million and $116 million for 2005 through 2009, respectively, and $684 million thereafter.

Progress Fuels had two coal supply contracts with PEF through 2005, 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. These contracts are renewable annually. Either party may terminate the contract with six months notice. 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 $358 million and $286 million for 2005 and 2006, respectively, with no obligations thereafter. The total cost incurred for these commitments in 2004, 2003 and 2002 was $301 million, $284 million and $289 million, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2015. Total purchases, for both energy and capacity, under these agreements amounted to $129 million, $124 million and $109 million for 2004, 2003 and 2002, respectively. Total capacity payments were $56 million, $55 million and $50 million for 2004, 2003 and 2002, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, at December 31, 2004 are $60 million, $63 million, $65 million, $66 million and $67 million for 2005 through 2009, respectively, and $244 million thereafter.

PEF has ongoing purchased power contracts with certain cogenerators (qualifying facilities) for 821 MW of capacity with expiration dates ranging from 2005 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. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $248 million, $244 million and $235 million for 2004, 2003 and 2002, respectively. Minimum expected future capacity payments under these contracts at December 31, 2004 are $271 million, $279 million, $289 million, $298 million and $263 million for 2005 through 2009, respectively, and $3.8 billion thereafter. 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.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC, for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007 to April 30, 2027. The total cost to PEF associated with the agreements is approximately $3.3 billion. The transactions are subject to several conditions precedent, which include obtaining the Florida Public Service Commission's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

PEF has purchase obligations related to various plant capital projects at the Hines Complex. Total payments under these contracts were $97 million, $137 million and $130 million for 2004, 2003, and 2002, respectively. Future obligations under these contracts are $51 million for 2005.

OTHER PURCHASE OBLIGATIONS

PEF has long-term service agreements for the Hines Complex. Total payments under these contracts were $11 million, $3 million and $1 million for 2004, 2003 and 2002, respectively. Future obligations under these contracts are $6 million, $18 million, $11 million, $16 million and $14 million for 2005 through 2009, respectively, with approximately $93 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. At December 31, 2004, no purchases have been made under these contracts. Future obligations under these contracts are $34 million, $20 million and $25 million in 2005, 2006 and 2007, respectively, and $6 million in 2008 and 2009.

The Company incurred expenses related to various other purchase obligations allocated from PESC of $6 million for 2004 and 2003 and $5 million for 2002.

B. Other Commitments

The Company has certain future commitments related to synthetic fuel facilities purchased that provide for contingent payments (royalties). The related agreements and amendments require the payment of minimum annual royalties of which the Company's share is approximately $13 million through 2007. As a result of the amendment, Company 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), each of approximately $37 million and $47 million at December 31, 2004 and 2003, representing the minimum amounts due through 2007, discounted at 6.05%. At December 31, 2004 and 2003, the portions of the asset and liability recorded that were classified as current were approximately $13 million. 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 none in 2004, $1 million in 2003 and $24 million in 2002. Future expected royalty payments are approximately $13 million for 2005 through 2007. The Company has the right in the related agreements and their amendments that allow the Company to escrow those payments if certain conditions in the agreements are met. The Company has exercised that right and retained 2004 and 2003 royalty payments of approximately $20 million and $22 million, respectively, 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 $45 million, $40 million and $49 million during 2004, 2003 and 2002, respectively. These amounts include rent expense allocated from PESC to the Company of $12 million for 2004, 2003 and 2002. PEF's rent expense totaled $14 million, $17 million and $16 million during 2004, 2003 and 2002, respectively. These amounts include rent expense allocated from PESC to PEF of $10 million for 2004, 2003 and 2002.

In addition, PTC has entered into capital leases for equipment. Assets recorded under capital leases totaled $2 million and $4 million at December 31, 2004 and 2003, 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 10). PEF does not have any capital leases.

Minimum annual rental payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable leases at December 31, 2004 are:

(in millions)	Capital Leases	Operating Leases	
		Florida Progress	Progress Energy Florida
2005	$ 2	$ 22	$ 11
2006	2	19	9
2007	1	36	28
2008	1	37	30
2009	1	36	29
Thereafter	8	170	132
	$ 15	$ 320	$ 239
Less amount representing imputed interest	(5)		
Present value of net minimum lease payments under capital lease	$ 10		

FPC, excluding PEF, 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 2005 through 2009, in millions is $31, $22, $13, $8 and $6, respectively and $16 million thereafter. Rents received under operating leases totaled $63 million, $46 million and $53 million for 2004, 2003 and 2002, respectively.

PEF is the lessor of electric poles, streetlights and other facilities. Rents received are based on a fixed minimum rental where price varies by type of equipment and totaled $63 million, $56 million and $52 million for 2004, 2003 and 2002, respectively. Minimum rentals receivable (excluding streetlights) under noncancelable leases for 2005 through 2009, in millions is $5, $1, $1, $1 and $1, respectively, and $8 million thereafter. Streetlight rentals were $40 million, $38 million and $34 million for 2004, 2003 and 2002 respectively. Future streetlight rentals would approximate 2004 revenues.

D. Guarantees

To facilitate commercial transactions of the Company's subsidiaries Progress Energy and certain wholly owned subsidiaries enter into agreements providing future financial or performance assurances to third parties (See Note 17). At December 31, 2004, Progress Fuels had issued guarantees on behalf of third parties with an estimated maximum exposure of approximately $10 million. These guarantees support synthetic fuel operations. At December 31, 2004, management does not believe conditions are likely for significant performance under these agreements.

In connection with the sale of partnership interests in Colona (See Note 4B), Progress Fuels indemnified the buyers against any claims related to Colona resulting from violations of any environmental laws. Although the terms of the agreement provide for no limitation to the maximum potential future payments under the indemnification, the Company has estimated that the maximum total of such payments would not be material.

E. Claims and Uncertainties

OTHER CONTINGENCIES

1. Franchise Litigation

Three cities, with a total of approximately 18,000 customers, have litigation pending against PEF in various circuit courts in Florida. As previously reported, 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. The circuit courts in those cases 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 the cities to determine the value of PEF's electric distribution system within the cities through arbitration.

Arbitration in one of the cases (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 (the City) 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, which, according to the award, decrease over time. 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. While the City has not yet definitively decided whether it will acquire the system, on April 26, 2004, the City Commission voted to proceed with the acquisition. The City sought and received wholesale power supply bids and on June 24, 2004, executed a wholesale power supply contract with PEF. On May 12, 2004, the City solicited bids to operate and maintain the distribution system and awarded a contract in January 2005. The City has indicated that its goal is to begin electric operations in June 2005. On February 10, 2005, PEF filed a petition with the Florida Public Service Commission to relieve the Company of its statutory obligation to serve customers in Winter Park on June 1, 2005, or at such time when the City is able to provide retail service. At this time, whether and when there will be further proceedings regarding the City of Winter Park cannot be determined.

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; however, on January 18, 2005, it issued a request for proposals for wholesale power supply and to operate and maintain the distribution system. Proposals are due in early March 2005. In February 2005, the Town Commission also voted to put the issue of whether to acquire the distribution system to a voter referendum on or before October 2, 2005. At this time, whether and when there will be further proceedings regarding the Town of Belleair cannot be determined.

Arbitration in the remaining city's litigation (the 1,500-customer City of Edgewood) has not yet been scheduled. On February 17, 2005, the parties filed a joint motion to stay the litigation for a 90-day period during which the parties will discuss potential settlement.

A fourth city (the 7,000-customer City of Maitland) is contemplating municipalization and has indicated its intent to proceed with arbitration to determine the value of PEF's electric distribution system within the City. Maitland's franchise expires in August 2005. At this time, whether and when there will be further proceedings regarding the City of Maitland cannot be determined.

As part of the above litigation, two appellate courts 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 filed an appeal with the Florida Supreme Court to resolve the conflict between the two appellate courts. On October 28, 2004, the Court issued a decision holding that PEF must collect from its customers and remit to the cities franchise fees during the interim period when the city exercises its purchase option or executes a new franchise agreement. The Court's decision should not have a material impact on the Company.

2. <u>DOE Litigation</u>

Pursuant to the Nuclear Waste Policy Act of 1982, the predecessors to PEF entered into contracts 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.

DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, PEF filed a complaint with the United States

Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel (SNF) by failing to accept SNF from PEF facilities on or before January 31, 1998. Damages due to DOE's breach will likely exceed $100 million. Approximately 60 cases involving the Government's actions in connection with SNF are currently pending in the Court of Federal Claims.

DOE and the PEF parties have agreed to a stay of the lawsuit, including discovery. The parties agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously-filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of SNF and high level waste (HLW) by which the Government was contractually obligated to accept contract holders' SNF and/or HLW, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues are expected to be presented in the trials that are scheduled to occur by April 2005. Resolution of these issues in other cases could facilitate agreements by the parties in the PEF lawsuit, or at a minimum, inform the Court of decisions reached by other courts if they remain contested and require resolution in this case. The trial court has continued this stay until June 24, 2005.

With certain modifications and additional approval by the NRC, including the installation of onsite dry storage facilities at PEF's nuclear unit, Crystal River Unit No. 3 (CR3), PEF's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on PEF's system through the expiration of the operating license for CR3.

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. In January 2003, the State of Nevada, Clark County, Nevada and the City of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. EPA is currently reworking the standard but has not stated when the work will be complete. DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, DOE announced it would not submit the license application until mid-2005 or later. Also in November 2004, Congressional negotiators approved $577 million for fiscal year 2005 for the Yucca Mountain project, approximately $300 million less than requested by DOE but approximately the same as approved in 2004. The DOE continues to state it plans to begin operation of the repository at Yucca Mountain in 2010. PEF cannot predict the outcome of this matter.

3. 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 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.

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 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. Because the motion has now been outstanding for over a year, a ruling on the motion is expected at any time.

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.

The Company cannot predict the outcome of this matter, but will vigorously defend against the allegations.

4. Synthetic Fuel Tax Credits

At December 31, 2003, Florida Progress, through its subsidiaries, was 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 Code (Code). In June 2004, Progress Fuels sold, in two transactions, a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its majority owned synthetic fuel operations. The Company is now a minority owner in Colona, but continues to consolidate Colona in accordance with FASB Interpretation No. 46R. Florida Progress, through its subsidiaries, is currently a majority owner in two synthetic fuel entities and a minority owner in four synthetic fuel entities, including Colona. 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. The amount of Section 29 credits that the Company is allowed to claim in any calendar year is limited by the amount of the Company's regular federal income tax liability. Synthetic fuel tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. All majority-owned and minority-owned entities received private letter rulings (PLRs) from the Internal Revenue Service (IRS) with respect to their synthetic fuel operations. However, these PLR's do not address the placed–in-service date determinations. The PLRs do not limit the production on which synthetic fuel credits may be claimed. Total Section 29 credits generated to date are approximately $918 million, of which $432 million has been used to offset regular federal income tax liability and $481 million are being carried forward as deferred alternative minimum tax credits. Also $5 million has not been recognized due to the decrease in tax liability from the 2004 hurricane damage. The current Section 29 tax credit program expires at the end of 2007.

IMPACT OF HURRICANES

For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 4.9 million tons of synthetic fuel and the Company recorded $127 million of Section 29 tax credits. The amount of synthetic fuel sold and tax credits recorded in 2004 was impacted by hurricane costs which reduced the Company's projected 2004 regular tax liability.

For the nine months ended September 30, 2004, the Company's synthetic fuel facilities sold 4.6 million tons of synthetic fuel, which generated an estimated $119 million of Section 29 tax credits. Due to the anticipated decrease in the Company's tax liability as a result of expenses incurred for the 2004 hurricane damage, the Company estimated that it would be able to use in 2004, or carry forward to future years, only $72 million of these Section 29 tax credits. As a result, the Company recorded a charge of $47 million related to Section 29 tax credits at September 30, 2004.

On November 2, 2004, PEF filed a petition with the FPSC to recover $252 million of storm costs plus interest from customers over a two-year period. Based on a reasonable expectation at December 31, 2004, that the FPSC will grant the requested recovery of the storm costs, the Company's loss from the casualty is less than originally anticipated. As of December 31, 2004, the Company estimates that it will be able to use in 2004, or carry forward to future years, $127 million of these Section 29 tax credits. Therefore, the Company recorded tax credits of $55 million for the quarter ended December 31, 2004, which the Company now anticipates can be used. For the year ended December 31, 2004, the Company's synthetic fuel facilities sold 4.9 million tons of synthetic fuel, which generated an estimated $132 million of Section 29 tax credits. As of December 31, 2004, the Company anticipates that approximately $5 million of tax credits related to synthetic fuel sold during the year could not be used and have not been recognized.

The Company believes its right to recover storm costs is well established, however, the Company cannot predict the outcome of this matter. If the FPSC should deny PEF's petition for the recovery of storm costs in 2005, there could be a material impact on the amount of 2005 synthetic fuels production and results of operations.

IRS PROCEEDINGS

In September 2002, all of Florida Progress' majority-owned synthetic fuel entities at that time, 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.

In February 2004, subsidiaries of the Company finalized execution of the Colona Closing Agreement with the IRS 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 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 concluded the PFA program with respect to Colona.

In July 2004, Progress Energy was notified that the IRS field auditors anticipate taking an adverse position regarding the placed-in-service date of the Company's four Earthco synthetic fuel facilities. Due to the auditors' position, the IRS has decided to exercise its right to withdraw from the PFA program with Progress Energy. With the IRS's withdrawal from the PFA program, the review of he Company's Earthco facilities is back on the normal procedural audit path of the Company's tax returns. Through December 31, 2004, based on its ownership percentage, the Company has used or carried forward $550 million of tax credits generated by Earthco facilities. If these credits were disallowed, Florida Progress' one time exposure for cash tax payments would be $64 million (excluding interest), and earnings and equity would be reduced by $550 million, excluding interest.

On October 29, 2004, Progress Energy received the IRS field auditors' report concluding that the Earthco facilities had not been placed in service before July 1, 1998, and that the tax credits generated by those facilities should be disallowed. The Company disagrees with the field audit team's factual findings and believes that the Earthco facilities were placed in service before July 1, 1998. The Company also believes that the report applies an inappropriate legal standard concerning what constitutes "placed in service." The Company intends to contest the field auditors' findings and their proposed disallowance of the tax credits.

Because of the disagreement between the Company and the field auditors as to the proper legal standard to apply, the Company believes that it is appropriate and helpful to have this issue reviewed by the National Office of the IRS, just as the National Office reviewed the issues involving chemical change. Therefore, the Company is asking the National office to clarify the legal standard and has initiated this process with the National Office. The Company believes that the appeals process, including proceedings before the National Office, could take up to two years to complete, however, it cannot control the actual timing of resolution and cannot predict the outcome of this matter.

In management's opinion, the Company is complying with all the necessary requirements to be allowed such credits under Section 29, and, although it cannot provide certainty, it believes that it will prevail in these matters. Accordingly, while the Company has adjusted its synthetic fuel production for 2004 in response to the effects of the hurricane damage on its 2004 tax liability, it has no current plans to alter its synthetic fuel production schedule for future years as a result of the IRS field auditors' report. However, should the Company fail to prevail in these matters, there could be a material liability for previously taken Section 29 tax credits, with a material adverse impact on earnings and cash flows.

PROPOSED ACCOUNTING RULES FOR UNCERTAIN TAX POSITIONS

In July 2004, the FASB stated that it plans to issue an exposure draft of a proposed interpretation of SFAS No. 109, "Accounting for Income Taxes," that would address the accounting for uncertain tax positions. The FASB has indicated that the interpretation would require that uncertain tax benefits be probable of being sustained in order to record such benefits in the financial statements. The exposure draft is expected to be issued in the first quarter of 2005. The Company cannot predict what actions the FASB will take or how any such actions might ultimately affect the Company's financial position or results of operations, but such changes could have a material impact on the Company's evaluation and recognition of Section 29 tax credits.

PERMANENT SUBCOMMITTEE

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 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.

SALE OF PARTNERSHIP INTEREST

In June 2004, the Company through its subsidiary, Progress Fuels, sold, in two transactions, a combined 49.8% partnership interest in Colona Synfuel Limited Partnership, LLLP, one of its synthetic fuel facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gain from the sales will be recognized on a cost recovery basis. The Company's book value of the interests sold totaled approximately $3 million. The Company received total gross proceeds of $10 million in 2004. Based on projected production and tax credit levels, the Company anticipates receiving approximately $24 million in 2005, approximately $31 million in 2006, approximately $32 million in 2007 and approximately $8 million through the second quarter of 2008. In the event that the synthetic fuel tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuel tax credits, the amount of proceeds realized from the sale could be significantly impacted.

IMPACT OF CRUDE OIL PRICES

Although the Internal Revenue Code Section 29 tax credit program is expected to continue through 2007, recent unprecedented and unanticipated increases in the price of oil could limit the amount of those credits or eliminate them altogether for one or more of the years following 2004. This possibility is due to a provision of Section 29 that provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the "Annual Average Price") exceeds a certain threshold value (the "Threshold Price"), the amount of Section 29 tax credits are reduced for that year. Also, if the Annual Average Price increases high enough (the "Phase Out Price"), the Section 29 tax credits are eliminated for that year. For 2003, the Threshold Price was $50.14 per barrel and the Phase Out Price was $62.94 per barrel. The Threshold Price and the Phase Out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase Out Price for a year, the amount by which Section 29 tax credits are reduced will depend on where the Average Annual Price falls in that continuum. For example, for 2003, if the Annual Average Price had been $56.54 per barrel, there would have been a 50% reduction in the amount of Section 29 tax credits for that year.

The Secretary of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the Energy Information Agency (EIA). Because the EIA publishes its information on a three month lag, the Secretary of the Treasury finalizes its calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2003 was published in April 2004.

Although the official notice for 2004 is not expected to be published until April of 2005, the Company does not believe that the Annual Average Price for 2004 will reach the Threshold Price for 2004. Consequently, the Company does not expect the amount of its 2004 Section 29 tax credits to be adversely affected by oil prices.

The Company cannot predict with any certainty the Annual Average Price for 2005 or beyond. Therefore, it cannot predict whether the price of oil will have a material effect on it synthetic fuel business after 2004. However, if during 2005 through 2007, oil prices remain at historically high levels or increase, the Company's synthetic fuel business may be adversely affected for those years and, depending on the magnitude of such increases in oil prices, the adverse affect for those years could be material and could have an impact on the Company's results of operations and synthetic fuel production plans.

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 and PEF's financial position or results of operations.

22. SUBSEQUENT EVENTS

Sale of Progress Rail

On February 18, 2005, Progress Energy announced it has entered into a definitive agreement to sell Progress Rail to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Gross cash proceeds from the transaction will be $405 million, subject to working capital adjustments. The sale is expected to close by mid-2005, and is subject to various closing conditions customary to such transactions. Proceeds from the sale are expected to be used to reduce debt. The Company expects to report Progress Rail as a discontinued operation in the first quarter of 2005. The carrying amounts for the assets and liabilities of the discontinued operations disposal group included in the Consolidated Balance Sheets at December 31, are as follows:

(in millions)	**2004**	2003
Total current assets	**$ 378**	$ 373
Total property, plant & equipment (net)	**202**	184
Total other assets	**28**	64
Total current liabilities	**156**	114
Total long-term liabilities	**3**	3
Total capitalization	**449**	504

Cost Management Initiative

On February 28, 2005, as part of a previously announced cost management initiative, the executive officers of Progress Energy approved a workforce restructuring. The restructuring is expected to be completed in September of 2005. In addition to the workforce restructuring, the cost management initiative includes a voluntary enhanced retirement program.

In connection with the cost management initiative, the Company expects to incur one-time pre-tax charges of approximately $54 million. Approximately $9 million of that amount relates to payments for severance benefits, and will be recognized in the first quarter of 2005 and paid over time. The remaining approximately $45 million will be recognized in the second quarter of 2005 and relates primarily to post-retirement benefits that will be paid over time to those eligible employees who elect to participate in the voluntary enhanced retirement program. The total cost management initiative charges could change significantly depending upon how many eligible employees elect early retirement under the voluntary enhanced retirement program and the salary, service years and age of such employees.

23. SUPPLEMENTAL INFORMATION FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following supplemental unaudited information regarding the Company's oil and gas activities is presented pursuant to disclosure requirements of SFAS No. 69 "Disclosures About Oil and Gas Producing Activities."

A. Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization (See Notes 4A and 5B), at December 31 follows:

(in millions)	**2004**	2003
Capitalized Costs -		
Proved Properties being amortized	**$ 281**	$ 352
Unproved Properties not being amortized	**55**	60
	336	412
Less - Accumulated depreciation, depletion, and amortization	**(52)**	(35)
Net Capitalized Costs	**$ 284**	$ 377

B. Costs Incurred

There were no oil or gas exploration costs for the years ended 2004, 2003 and 2002. The following costs (in millions) were included in oil and gas producing activities during the years ended December 31,

(in millions)	**2004**	2003	2002
Property acquisition	**$ 7**	$ 169	$ 141
Development	**95**	105	16
Total Costs Incurred	**$ 102**	$ 274	$ 157

C. Results of Operations

The following summarizes the results of operations for the Company's oil and gas producing activities:

(in millions)	**2004**	2003	2002
Revenues - Sales	**$ 151**	$ 107	$ 36
Less:			
Production (lifting) costs	**28**	16	7
Depreciation, depletion, and amortization, and valuation provisions	**41**	33	11
Pretax Operating Income	**82**	58	18
Income tax expenses	**33**	19	6
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$ 49**	$ 39	$ 12

D. Estimated Quantities of Oil and Gas Reserves

At December 31, 2004, the Company had proved oil and gas reserves of 247 Bcfe estimated by Netherland Sewell & Associates, Inc., an independent engineering firm. These reserves are located entirely within the United States. Estimated net quantities of proven oil and gas reserves at December 31 for each of the last three years were as follows in Bcfe. Reserve quantities stated in Bcfe use an energy conversion factor of six units of gas for every one unit of oil.

January 1, 2002	69
Acquisitions	87
Extensions and discoveries	62
Production	(13)
December 31, 2002	205
Acquisitions	189
Extensions and discoveries	65
Production	(25)
Sales	(76)
December 31, 2003	**358**
Acquisitions	**12**
Extensions and discoveries	**58**
Production	**(30)**
Sales	**(151)**
December 31, 2004	**247**
Proved Developed Reserves included above:	
At December 31, 2002	179
At December 31, 2003	225
At December 31, 2004	**137**

E. Standardized Measure of Discounted Future Net Cash Flows (SMOG)

The following standardized disclosures required by FASB do not represent the results of operations based on its historical financial statements. In addition to requiring different determinations of revenue and costs, the disclosures exclude the impact of interest expense and corporate overhead. The following table sets forth, at December 31, 2004, the proven reserves and the present value, discounted at an annual rate of 10%, of future net revenues (revenues less production and development cost) attributable to these reserves.

	2004			2003			2002		
(in millions)	**Proved Developed**	**Proved Un-develop.**	**Total Proved**	Proved Dev.	ProvedUn-developed	Total Proved	Proved Developed	Proved Un-developed	Total Proved
Future Cash Inflows	**$ 806**	**$ 648**	**$ 1,454**	$ 1,283	$ 781	$ 2,064	$ 480	$ 419	$ 899
Less:									
Future production costs	**277**	**182**	**459**	357	203	560	138	100	238
Future development costs	**24**	**133**	**157**	40	122	162	7	58	65
Future income tax expense at 36%	**182**	**120**	**302**	319	164	483	121	94	215
Future Net Cash Flows	**323**	**213**	**536**	567	292	859	214	167	381
Less: annual discount	**120**	**115**	**235**	300	195	495	79	83	162
Standardized measure of discounted future net cash flows	**$ 203**	**$ 98**	**$ 301**	$ 267	$ 97	$ 364	$ 135	$ 84	$ 219

For purposes of determining the above cash flows, estimates were made of quantities of proved reserves and the periods during which they are expected to produce. Future cash flows were computed by applying year-end prices to estimated annual future production from our proved oil and gas reserves. The year-end prices for crude oil and natural gas used in the estimation were $45.64 per Bbl and $6.21 per MMbtu, based on a December 31, 2004, Henry Hub spot market price. Future development and production costs were computed by applying year-end costs expected to be incurred in producing and further developing the proved reserves. The estimated future net cash flows were computed by application of a 10% per annum discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. Other assumptions of equal validity could give rise to substantially different results.

For the years ended, December 31, 2003 and 2002, $166 million of the increase to the SMOG was due to acquisition of reserves. For the years ended, December 31, 2004 and 2003, $166 million of the change was due to the sale of reserves and $53 million was due to increased development costs.

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for Florida Progress is as follows:

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 1,308**	**$ 1,495**	**$ 1,670**	**$1,462**
Operating income	**103**	**181**	**260**	**157**
Net income	**55**	**135**	**148**	**136**
Year ended December 31, 2003				
Operating revenues	$ 1,215	$ 1,207	$ 1,391	$ 1,195
Operating income	126	122	193	64
Net income	92	114	174	67

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. Certain reclassifications have been made to previously reported amounts to conform to the current year's presentation. Fourth quarter 2004 includes a goodwill impairment charge related to the Company's coal mining business of $8 million before and after tax (See Note 9) and a $31 million after-tax gain on the sale of natural gas assets (See Note 4A). Fourth quarter 2004 also includes the recording of $47 million of Section 29 tax credits (See Note 21E). Third quarter 2004 includes the reversal of $55 million of Section 29 tax credits (See Note 21E). Fourth quarter 2003 includes an impairment related to Kentucky May of $15 million ($10 million after-tax) (See Note 10).

Summarized quarterly financial data for PEF is as follows:

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2004				
Operating revenues	**$ 784**	**$ 860**	**$ 1,029**	**$852**
Operating income	**103**	**157**	**244**	**114**
Net income	**50**	**84**	**140**	**61**
Year ended December 31, 2003				
Operating revenues	$ 728	$ 767	$ 904	$ 753
Operating income	135	116	184	93
Net income	71	62	115	49

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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

1. Report in columns (b),(c),(d) 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 Preceding Quarter/Year		(2,365,547)		
2	Preceding Quarter/Year Reclassification from Account 219 to Net Income				
3	Preceding Quarter/Year Changes in Fair Value		(1,339,368)		
4	Total (lines 2 and 3)		(1,339,368)		
5	Balance of Account 219 at End of Preceding Quarter/Year / Beginning of		(3,704,915)		
6	Current Quarter/Year Reclassifications from Account 219 to Net Income				
7	Current Quarter/Year Changes in Fair Value		3,704,915		
8	Total (lines 6 and 7)		3,704,915		
9	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (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	(318,366)		(2,683,913)	[redacted]	
2	239,750		239,750		
3			(1,339,368)		
4	239,750		(1,099,618)	296,354,489	295,254,871
5	(78,616)		(3,783,531)	[redacted]	
6	8,621		8,621		
7			3,704,915		
8	8,621		3,713,536	334,882,384	338,595,920
9	(69,995)		(69,995)	[redacted]	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,977,137,106	7,974,605,866
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	416,571,897	416,571,897
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,393,709,003	8,391,177,763
9	Leased to Others		
10	Held for Future Use	7,921,254	7,921,254
11	Construction Work in Progress	419,736,394	419,736,394
12	Acquisition Adjustments	-6,307,202	-6,307,202
13	Total Utility Plant (8 thru 12)	8,815,059,449	8,812,528,209
14	Accum Prov for Depr, Amort, & Depl	4,187,956,959	4,187,401,216
15	Net Utility Plant (13 less 14)	4,627,102,490	4,625,126,993
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,095,202,183	4,095,202,183
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	94,615,590	94,059,847
22	Total In Service (18 thru 21)	4,189,817,773	4,189,262,030
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	-1,860,814	-1,860,814
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,187,956,959	4,187,401,216

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
	555,743				14
	1,975,497				15
					16
					17
					18
					19
					20
	555,743				21
	555,743				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	555,743				33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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		415,230
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)	103,037,800	22,464
10	SUBTOTAL (Total 8 & 9)	103,037,800	
11	Spent Nuclear Fuel (120.4)	111,517,438	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	145,446,991	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	69,108,247	
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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
		415,230	3
			4
			5
		415,230	6
			7
			8
		103,060,264	9
		103,060,264	10
	111,517,438		11
			12
-24,302,944	111,517,438	58,232,497	13
		45,242,997	14
			15
			16
			17
			18
			19
			20
			21
			22

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

$111,517,438 Transferred to 120.5 Accum Prov for Amortization of Nuclear Fuel Assemblies.

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

$111,517,438 Transferred from 120.4 Spent Nuclear Fuel.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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		2,831,178
4	(303) Miscellaneous Intangible Plant	116,397,241	1,717,048
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	116,397,241	4,548,226
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,450,314	500,432
9	(311) Structures and Improvements	283,136,989	2,445,156
10	(312) Boiler Plant Equipment	813,414,966	22,520,368
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	438,227,035	13,157,297
13	(315) Accessory Electric Equipment	162,947,468	-4,323,540
14	(316) Misc. Power Plant Equipment	28,637,403	832,350
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,732,814,175	35,132,063
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	41,218	
19	(321) Structures and Improvements	244,386,466	-22,686,394
20	(322) Reactor Plant Equipment	265,059,265	27,948,222
21	(323) Turbogenerator Units	89,358,237	2,830,497
22	(324) Accessory Electric Equipment	182,326,046	-1,987,105
23	(325) Misc. Power Plant Equipment	40,636,519	2,412,090
24	(326) Asset Retirement Costs for Nuclear Production	77,064,813	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	898,872,564	8,517,310
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	18,646,067	113,215
38	(341) Structures and Improvements	76,746,366	27,830,665
39	(342) Fuel Holders, Products, and Accessories	50,588,339	19,927,886
40	(343) Prime Movers	679,605,759	-72,983,102
41	(344) Generators	225,492,202	42,170,088
42	(345) Accessory Electric Equipment	124,417,711	-2,115,776
43	(346) Misc. Power Plant Equipment	11,954,614	2,495,621

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
			2,831,178		3
918,594			117,195,695		4
918,594			120,026,873		5
					6
					7
			6,950,746		8
337,530			285,244,615		9
5,992,980			829,942,354		10
					11
3,977,930			447,406,402		12
536,175			158,087,753		13
147,319			29,322,434		14
					15
10,991,934			1,756,954,304		16
					17
			41,218		18
2,333,725			219,366,347		19
23,731,403			269,276,084		20
440,251			91,748,483		21
4,097,125			176,241,816		22
2,417,567			40,631,042		23
			77,064,813		24
33,020,071			874,369,803		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			18,759,282		37
1,573,763			103,003,268		38
259,418			70,256,807		39
12,267,667		6,200,889	600,555,879		40
129,318		-6,200,889	261,332,083		41
893,306			121,408,629		42
28,223			14,422,012		43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	1,187,451,058	17,438,597
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,819,137,797	61,087,970
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	52,074,329	11,154,909
49	(352) Structures and Improvements	18,220,507	46,259
50	(353) Station Equipment	411,023,801	17,021,302
51	(354) Towers and Fixtures	69,029,576	16,526
52	(355) Poles and Fixtures	242,606,459	13,776,698
53	(356) Overhead Conductors and Devices	200,202,294	11,835,552
54	(357) Underground Conduit	6,853,092	157,888
55	(358) Underground Conductors and Devices	9,494,272	2,130
56	(359) Roads and Trails	1,923,175	431
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,011,427,505	54,011,695
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,962,935	-304,585
61	(361) Structures and Improvements	19,334,943	1,474,679
62	(362) Station Equipment	342,011,685	11,599,682
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	401,876,046	26,518,768
65	(365) Overhead Conductors and Devices	433,345,156	48,969,064
66	(366) Underground Conduit	144,705,244	14,875,179
67	(367) Underground Conductors and Devices	403,499,689	26,124,571
68	(368) Line Transformers	388,836,184	25,575,513
69	(369) Services	381,868,466	46,226,394
70	(370) Meters	122,374,058	2,768,460
71	(371) Installations on Customer Premises	2,927,207	-576,018
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	227,226,491	26,875,621
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,889,968,104	230,127,328
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	10,201,358	1,173,436
78	(390) Structures and Improvements	74,262,765	13,558,931
79	(391) Office Furniture and Equipment	34,800,512	2,587,194
80	(392) Transportation Equipment	112,828,556	10,392,917
81	(393) Stores Equipment	3,120,964	2,739
82	(394) Tools, Shop and Garage Equipment	9,416,956	1,838,718
83	(395) Laboratory Equipment	4,078,916	74,505
84	(396) Power Operated Equipment	2,603,913	125,552
85	(397) Communication Equipment	61,803,449	6,341,454
86	(398) Miscellaneous Equipment	3,408,562	986,297
87	SUBTOTAL (Enter Total of lines 77 thru 86)	316,525,951	37,081,743
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)	316,525,951	37,081,743
91	TOTAL (Accounts 101 and 106)	8,153,456,598	386,856,962
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)	8,153,456,598	386,856,962

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
15,151,695			1,189,737,960		45
59,163,700			3,821,062,067		46
					47
			63,229,238		48
			18,266,766		49
2,311,059	132,806		425,866,850		50
			69,046,102		51
2,181,148	135,508		254,337,517		52
1,990,831	56,628		210,103,643		53
			7,010,980		54
			9,496,402		55
			1,923,606		56
					57
6,483,038	324,942		1,059,281,104		58
					59
			21,658,350		60
25,017			20,784,605		61
4,641,197	101,196		349,071,366		62
					63
2,395,215			425,999,599		64
19,592,573			462,721,647		65
719,001			158,861,422		66
2,587,206			427,037,054		67
11,607,800			402,803,897		68
11,672,064			416,422,796		69
2,324,365	-1,026		122,817,127		70
			2,351,189		71
					72
6,329,949			247,772,163		73
					74
61,894,387	100,170		3,058,301,215		75
					76
	20,000		11,394,794		77
90,569	1,481,440		89,212,567		78
22,362,217			15,025,489		79
			123,221,473		80
16,953			3,106,750		81
			11,255,674		82
521,198			3,632,223		83
			2,729,465		84
980	1,156,660		69,300,583		85
767,373			3,627,486		86
23,759,290	2,658,100		332,506,504		87
					88
					89
23,759,290	2,658,100		332,506,504		90
152,219,009	3,083,212		8,391,177,763		91
					92
					93
					94
152,219,009	3,083,212		8,391,177,763		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	05/05	267,012
6				
7				
8	OTHER LAND 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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	60HNG3CRP0 HINES 3 CC MASTER	179,689,143
2	605011616T1 VANDOLAH-WHIDDEN	12,891,057
3	CP HEC PB1 2004 FALL MAJOR	12,754,310
4	CP HEC PB1 2004 SPRING MAJOR	12,533,082
5	CP TB 2004 SPRING HGP & REFURB	11,797,278
6	S COASTAL INDIRECT PROJECT	6,579,402
7	CP IC P11 MAJOR INSPECTION	5,537,715
8	HINES PB4-MASTER	5,013,954
9	FPC EMS Upgrade Conversion	4,954,096
10	60GB9D NRC DIR SEC COMP MEAS	4,309,040
11	605011179D1 DUNDEE TRANSF	4,275,335
12	60896 DIST OPS & SUPPORT BDGT	3,643,031
13	CTE - SECTIONALIZERS (ADD SEG)	3,590,097
14	605011648T1 DEMPSEY (CFEC)	3,426,963
15	605011444S5 HINES PHASE III	3,257,278
16	ANCL #2 L-O TURBINE BLADE REPLACEME	3,154,316
17	STEAM GENERATOR REPLACEMENT STUDY	2,979,954
18	CP DEB P7 MAJOR INSPECTION	2,793,281
19	CP IC P10 MAJOR INSPECTION	2,534,490
20	CP HEC PB2A FALL CI	2,418,892
21	60GB9D NRC SECURITY ORDERS	2,414,511
22	60896 PQ&R	2,364,725
23	605011489T4 HAINES CRK-TAV	2,169,907
24	605011616S1 VANDOLAH TERM 230K	2,089,423
25	60440-WC5906	1,865,281
26	CP IC P12 COMB INSPECTION	1,823,839
27	CTE - PADMNT XFMR REPLACEMENT	1,783,664
28	CP UF HOT SECTION EXCHANGE	1,747,802
29	60X00 WINTER PARK	1,733,758
30	60208D TRIP TRANSFORMER PURCH	1,694,484
31	605011682T1 ATWATER-LIBERTY	1,681,528
32	60896 MOBILE_LINK	1,653,361
33	605011648S3 OLD TOWN SWITCH	1,620,411
34	CP IC P14 COMBUSTION INSPECT	1,526,991
35	60AN0CRP0 PIPELINE LEAK DET	1,510,007
36	CP IC P13 COMBUSTION INSPECT	1,503,128
37	608961076D1 ODESSA	1,468,710
38	60440D CONWAY OC-PURCHASE LAND	1,400,262
39	605011830T1 HINES PB4 H-WLW	1,353,985
40	60501940T1 BI RELOC FOR CR 486	1,335,022
41	60GB9D ALTERNATE AC PWR MASTER	1,304,236
42	60CR5CRP0 BOTTOM ASH REPL	1,263,804
43	TOTAL	419,736,394

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	605011235S1 AVALON TRANSFORMER	1,262,387
2	CTE - U/G SECTIONALIZER	1,237,626
3	CTE - AUTOMATION	1,223,559
4	CP IC P7 MAJOR INSPECTION	1,179,343
5	608961575D1 SUNFLOWER	1,129,664
6	605011067T1 INGLIS-CITRUS SPGS	1,084,623
7	UG TRANSFORMER BLANKET	1,069,269
8	60CR4CRP4 CR4 ASH PIPING PROJ	1,050,812
9	60810948T2 JA REPL POLES	1,041,007
10	60501939T8 CSB69KV RELO CR 491	1,024,881
11	CTE-TRE-0824D8-MOBILE	1,017,113
12	Other Minor Projects	81,974,557
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		
42		
43	TOTAL	419,736,394

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	3,946,230,425	3,946,230,425		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	263,999,924	263,999,924		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,494,018	1,494,018		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,386,181	6,386,181		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil	548,701	548,701		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	272,428,824	272,428,824		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	152,219,009	152,219,009		
13	Cost of Removal	14,104,033	14,104,033		
14	Salvage (Credit)	48,765,833	48,765,833		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	117,557,209	117,557,209		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17		-5,899,857	-5,899,857		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,095,202,183	4,095,202,183		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,265,927,851	1,265,927,851		
21	Nuclear Production	622,297,410	622,297,410		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	442,776,567	442,776,567		
25	Transmission	460,973,509	460,973,509		
26	Distribution	1,172,693,477	1,172,693,477		
27	General	130,533,369	130,533,369		
28	TOTAL (Enter Total of lines 20 thru 27)	4,095,202,183	4,095,202,183		

Schedule Page: 219 Line No.: 1 Column: c

See Footnote for Page 110 Line No. 5 for Beginning Balance Adjustment of $5,862,458.

Schedule Page: 219 Line No.: 9 Column: c

Provision for Steam 311.0-315.0 & 316.3 Bartow-Anclote Pipeline.

Schedule Page: 219 Line No.: 17 Column: c

Adjustments to Reserve:

Clearing Accounts	($6,934,882)
Adjustments & Transfers	$1,035,025
Total	($5,899,857)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	90,516,921	103,298,488	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)	139,039,999	94,036,240	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	21,681,603	47,194,097	Power Supply
8	Transmission Plant (Estimated)	986,329	2,418,700	Transmission
9	Distribution Plant (Estimated)	5,149,093	11,602,490	Customer Service
10	Assigned to - Other (provide details in footnote)	552,633	1,136,699	Various
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	167,409,657	156,388,226	
12	Merchandise (Account 155)	424,410	204,989	Customer Service
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)	9,361,873	19,516,453	Various
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	267,712,861	279,408,156	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Balance of $130,195,768 changed by $37,213,889 for reclass of CT Turbine from CWIP (1071000) to Inventory (15420PP).

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

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.

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

Account 163- Stores Expense Undistributed was charged with $549,367 and credited with $312,959 for a net charge of $236,409 during 2004. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2004.

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)	2005 No. (d)	2005 Amt. (e)
1	Balance-Beginning of Year	3,880.00	912,089	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:	47,224.00	24,584,041		
9	Various Purchases and				
10	Transfers (Including				
11	Morgan Stanley, AEP, Cons				
12	lation Pwr Src, Pub Svc				
13	Co of NewMex, Reliant,				
14	Millenium Evn Grp)				
15	Total	47,224.00	24,584,041		
16					
17	Relinquished During Year:				
18	Charges to Account 509	144,610.00	15,238,599		
19	Other:				
20	True-up	-3,246.00	4,105		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	35,393.00	10,253,426	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				

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.

2006		2007		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
125,653.00		125,653.00		2,635,946.00		3,016,785.00	912,089	1
								2
								3
						125,653.00		4
								5
								6
								7
						47,224.00	24,584,041	8
								9
								10
								11
								12
								13
								14
						47,224.00	24,584,041	15
								16
								17
						144,610.00	15,238,599	18
								19
						-3,246.00	4,105	20
								21
								22
								23
								24
								25
								26
								27
								28
125,653.00		125,653.00		2,635,946.00		3,048,298.00	10,253,426	29
								30
								31
								32
								33
								34
								35
3,343.00		3,343.00		67,600.00		80,972.00		36
								37
								38
								39
3,343.00		3,343.00		67,600.00		80,972.00		40
								41
								42
								43
					2,397,821		2,397,821	44
								45
								46

Schedule Page: 228 Line No.: 1 Column: b

Beginning balance includes correction in tons on hand recorded after 2003 filing.

Schedule Page: 228 Line No.: 20 Column: a

True-up required for accounting reconciliation.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/2004	End of 2004/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Storm Extraordinary Property			0		
2	Loss - Wholesale (Ferc letter					
3	dated 1/7/2005, Docket No.					
4	AC05-12-000, amortization expense			0		
5	consistent with recovery in			0		
6	rates)	12,645,771	12,645,771	4073701		12,645,771
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	12,645,771	12,645,771			12,645,771

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Taxes - FAS 109	114,114,000		4101000	5,059,000	109,055,000
2	Period of Amortization - Amortization occurs					
3	as temporary differences occur.					
4						
5	Nuclear Decom/Decontamination - Retail	4,782,597	272,795	5188200	1,734,926	3,320,466
6	Amortization Period = 12 months					
7						
8	Nuclear Decom/Decontamination - Whlse	553,199	30,311	5188200	192,770	390,740
9	Amortization Period = 12 months					
10						
11	Derivative Asset - MTM Oil		5,183,190			5,183,190
12						
13	Load Control Switches - Investment	2,862,348	804,868	1861902	317,464	3,349,752
14	Load Control Switches - Amortization	(1,265,104)		9080120	323,122	-1,588,226
15						
16	Deferred Energy Conservation Expense	(7,464,313)	6,524,784	9080110	7,187,005	-8,126,534
17						
18	Sebring Transition Rider	14,427,566	18,706	1861904	2,707,067	11,739,205
19	Sebring - Over(Under) Recovered	(1,539,917)	2,710,472	4044002	2,502,965	-1,332,410
20						
21	Interest on Tax Deficiency		1,100,000	4310024	205,572	894,428
22						
23	Deferred GPIF Asset	2,781,223	2,139,695	4560096	2,781,223	2,139,695
24						
25	Def Cap Expense - Retail - 01/04 -12/04		12,707,173	5572001	12,707,173	
26	Def Fuel Expense - Retail - 01/04 - 12/04		183,410,645	5572002	13,005,195	170,405,450
27	Def Fuel Expense - Retail - 01/03 - 12/03	173,449,717		5572002	173,449,717	
28	Def Fuel Expense - Retail - 01/02 - 12/02	37,777,646		5572002	37,777,646	
29	Def Fuel Expense - Full Req	2,482,402	6,997,007	5572002	4,422,652	5,056,757
30						
31	Deferred Environmental Cost Recovery	9,910,340	12,426,737	9350003	10,223,134	12,113,943
32	Accrued Environmental Cost Recovery	11,883,500	23,116,084	2284800	8,597,084	26,402,500
33						
34	RTO Set Up Costs	3,695,208	541,691			4,236,899
35						
36	Florida Minimum Pension Liability		7,153,634			7,153,634
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	368,450,412	265,137,792		283,193,715	350,394,489

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	4,960,592	36,744,713	Various	40,317,072	1,388,233
2						
3	FMS Solution Store Sell	165,066	7,295	402	1,409	170,952
4						
5	GE Turbine Transaction		29,584,281	402		29,584,281
6						
7	Major Storm Bonnie		487,702	402	397,657	90,045
8						
9	Hurricane Charley		305,690,314	402	180,750,476	124,939,838
10						
11	Hurricane Ivan		12,936,264	402	4,732,501	8,203,763
12						
13	Hurricane Francis		294,380,656	402	175,632,302	118,748,354
14						
15	Major Storms Final Sweeps		11,886,836	402	786,737	11,100,099
16						
17	Southern Company Capacity Dep		803,433	402		803,433
18						
19	Wholesale Storm Reclass			402	12,645,771	-12,645,771
20						
21	Hurricane Jeanne		244,585,548	402	169,453,556	75,131,992
22						
23	Vacation Pay Accrual	7,787,547	7,611,131	402	7,787,547	7,611,131
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	12,913,205				365,126,350

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	17,578,000	34,726,000
3	LIFE/MEDICAL BENEFITS	61,783,000	62,702,000
4	UNAMORTIZED INVESTMENT TAX CREDIT	15,990,000	13,648,000
5	REGULATORY LIABILITY	27,815,000	23,195,000
6	NUCLEAR DECOMMISSIONING	30,463,000	37,910,000
7	OTHER	-19,675,696	-4,902,596
8	TOTAL Electric (Enter Total of lines 2 thru 7)	133,953,304	167,278,404
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)	133,953,304	167,278,404

Notes

Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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		
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				
42				

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
						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
						42

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 at $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 therefore	1,167,518
8	Florida Public Service 4% Series "C" Bonds with called premium and	
9	interest held by General Gas and Electric Corporation	65,210
10	Reversal of over accrual of Federal Income Tax applicable to period	
11	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 applicable	
14	to 1944	92,552
15	To write off unamortized debt discount, premium and expense applicable	-979,793
16	to Bonds refunded in prior years	
17	Adjustment of original 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	Payroll taxes associated with stock option exercises	59,963
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	726,881,210

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 - 6 7/8%	80,000,000	765,503
4			1,069,599 D
5	FIRST MORTGAGE BONDS - 4.8%	425,000,000	4,585,299
6			1,513,000 D
7	FIRST MORTGAGE BONDS - 5.9%	225,000,000	3,013,280
8			571,500 D
9	FIRST MORTGAGE BONDS - 5.1%	300,000,000	3,278,935
10			594,000 D
11	MEDIUM TERM NOTE (SEBRING) - 6.67%	30,700,000	280,604
12			
13	MEDIUM TERM NOTE - 6.69%	40,000,000	242,220
14			
15	MEDIUM TERM NOTE - 6.72%	45,000,000	272,183
16			
17	MEDIUM TERM NOTE - 6.77%	45,000,000	271,939
18			
19	MEDIUM TERM NOTE - 6.81%	85,000,000	534,680
20			
21	MEDIUM TERM NOTE - 6.75%	150,000,000	5,528,498
22			436,500 D
23	POLLUTION CONTROL BONDS (CITRUS) 2002A	108,550,000	2,356,705
24			
25	POLLUTION CONTROL BONDS (CITRUS) 2002B	100,115,000	2,081,983
26			
27	POLLUTION CONTROL BONDS (CITRUS) 2002C	32,200,000	756,175
28			
29	RCA 3 YEAR	55,000,000	524,500
30			
31			
32			
33	TOTAL	2,021,565,000	32,288,760

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.
071801	071511	071801	071511	300,000,000	19,950,000	1
						2
020993	020108	020993	020108	80,000,000	5,500,004	3
						4
022103	030113	022103	030113	425,000,000	20,400,000	5
						6
021803	030133	021803	030133	225,000,000	13,275,000	7
						8
112103	120115	112103	120115	300,000,000	15,300,000	9
						10
040293	040108	042093	040108	11,800,002	877,106	11
						12
070197	070104	070197	070104		1,338,000	13
						14
072597	070105	072597	070105	45,000,000	3,024,000	15
						16
072597	070106	072597	070106	45,000,000	3,046,500	17
						18
072597	070107	072597	070107	85,000,000	5,788,500	19
						20
021398	020128	021398	020128	150,000,000	10,125,000	21
						22
082002	010127	082002	010127	108,550,000	1,351,689	23
						24
072402	010122	072402	010122	100,115,000	1,125,449	25
						26
081302	010118	081302	010118	32,200,000	372,080	27
						28
040103	040106	040103	040106	55,000,000	256,301	29
						30
						31
						32
				1,962,665,002	101,729,629	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	334,882,384
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	147,153,748
11		
12	Deductions Recorded on Books Not Deducted for Return	520,329,958
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	-708,576,079
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	293,790,011
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	102,826,504
30	True up Entries and Other Tax Benefits	-47,613,604
31	Total Federal Income Tax Provision (409120F - 409220F) True up Entries	55,212,900
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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	Income	10,704,106		55,212,900	39,741,630	2,016,000
3	FICA	-107		23,396,576	23,396,469	
4	Unemployment			267,144	267,144	
5	Special Fuel Tax	-1,295,102			-157,163	
6	Excise Tax					
7	Highway Use			46,369	46,369	
8	Payroll Tax				-2,003,141	
9	SUBTOTAL	9,408,897		78,922,989	61,291,308	2,016,000
10						
11	STATE TAXES					
12	Income	5,055,291		9,048,681	21,331,159	
13	Income Tax Subsidiary					
14	Gross Receipts	5,360,936		76,898,361	76,250,313	
15	Unemployment	-118		1,802,783	1,802,468	
16	Intangibles					
17	Regulatory Assessment	1,081,714		2,278,632	2,145,075	
18	Sales Tax-Company Use	14,358		104,986	105,197	
19	SUBTOTAL	11,512,181		90,133,443	101,634,212	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local			85,667,415	82,392,986	
23	Special Fuels-County			9,101	9,101	
24	Franchise-Local	5,031,389		73,932,495	72,865,045	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	5,031,389		159,609,011	155,267,132	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	25,952,467		328,665,443	318,192,652	2,016,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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				
(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)	Line No.
						1
28,191,376		68,215,864			-13,002,964	2
		15,337,920			8,058,656	3
					267,144	4
-1,137,939						5
						6
		46,369				7
2,003,141						8
29,056,578		83,600,153			-4,677,164	9
						10
						11
-7,227,187		10,030,248			-981,567	12
						13
6,008,984		76,898,361				14
198					1,802,783	15
						16
1,215,271		2,278,632				17
14,147		104,986				18
11,413		89,312,227			821,216	19
						20
						21
3,274,429		85,497,135			170,280	22
		9,101				23
6,098,838		73,932,495				24
						25
						26
						27
9,373,267		159,438,731			170,280	28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
38,441,258		332,351,111			-3,685,668	41

Schedule Page: 262 Line No.: 2 Column: f

Balance Sheet Reclasses

Prior Year Beginning Balance per FERC Form 1	14,725,787
Reclass Bond Payments from account 237 to account 236	(4,021,681)
Revised Beginning Balance Column (b) Line 2	10,704,106

Reclass Deferred Income Taxes in account 283.1 to Current Income Tax Payable account 236

Total adjustment to column (f)Line 2 2,016,000

Schedule Page: 262 Line No.: 27 Column: b

Page 112, Line 37, Column d

The difference between the taxes accrued amount on page 112, line 42 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 37	26,131,233	38,585,326
State Sales Tax on Purchases	(174,800)	(140,812)
County Sales Tax on Purchases	(3,966)	(3,256)
	25,952,467	38,441,258

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%						
4	7%						
5	10%	41,351,508			4114001	6,071,000	
6							
7							
8	TOTAL	41,351,508				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							
20							
21							
22							
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							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
35,280,508	27 years		5
			6
			7
35,280,508			8
			9
			10
			11
			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
			42
			43
			44
			45
			46
			47
			48

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	FAS 146 Deferred Exit Costs	2,970,075	131	1,951,550	703,928	1,722,453
2	Wholesale Deposits - SECI	3,880,000			890,000	4,770,000
3	Wholesale Deposits - Mirant				6,000,000	6,000,000
4	Wholesale Deposits - Other	520,502	131	1,268,243	1,116,204	368,463
5	Wholesale Deposits - FMPA	960,000			260,000	1,220,000
6	Deferred Rent Expense	632,322	various	48,980		583,342
7	Various	2,441,848	various	28,349,605	27,720,429	1,812,672
8						
9						
10						
11						
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						
42						
43						
44						
45						
46						
47	TOTAL	11,404,747		31,618,378	36,690,561	16,476,930

Schedule Page: 269 Line No.: 4 Column: b

Certain 2003 amounts were reclassified to conform with 2004 presentations.

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

Certain 2003 amounts were reclassified to conform with 2004 presentations.

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	7,182,000		996,000
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	7,182,000		996,000
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)	7,182,000		996,000
18	Classification of TOTAL			
19	Federal Income Tax	6,158,000		852,000
20	State Income Tax	1,024,000		144,000
21	Local Income Tax			

NOTES

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
						6,186,000	4
							5
							6
							7
						6,186,000	8
							9
							10
							11
							12
							13
							14
							15
							16
						6,186,000	17
							18
						5,306,000	19
						880,000	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	394,917,000	128,578,129	95,376,511
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	394,917,000	128,578,129	95,376,511
6	Other	7,194,000		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	402,111,000	128,578,129	95,376,511
10	Classification of TOTAL			
11	Federal Income Tax	346,409,000	109,754,024	82,067,782
12	State Income Tax	55,702,000	18,824,105	13,308,729
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (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
					7,194,000	435,312,618	2
							3
							4
					7,194,000	435,312,618	5
			7,194,000				6
							7
							8
			7,194,000		7,194,000	435,312,618	9
							10
			6,168,000		6,168,000	374,095,242	11
			1,026,000		1,026,000	61,217,376	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 6 Column: h

Amount was reclassified from Other to Electric during 2004.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - FAS 109	44,016,000		1,955,000
4				
5	Reclass ADIT to Current Tax Pa			
6	OCI / Minimun Pension Liabilit			
7	OCI / Minimum Pension Liabilit	-2,326,693		
8	Other	7,243,000	155,870,000	32,685,000
9	TOTAL Electric (Total of lines 3 thru 8)	48,932,307	155,870,000	34,640,000
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)	48,932,307	155,870,000	34,640,000
20	Classification of TOTAL			
21	Federal Income Tax	41,834,401	133,646,000	29,693,000
22	State Income Tax	7,097,906	22,224,000	4,947,000
23	Local Income Tax			

NOTES

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						
		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
						42,061,000	3
							4
		236	2,016,000			-2,016,000	5
				219	2,759,514	2,759,514	6
				219	2,326,693		7
						130,428,000	8
			2,016,000		5,086,207	173,232,514	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			2,016,000		5,086,207	173,232,514	19
							20
			1,729,000		4,527,663	148,586,064	21
			287,000		558,544	24,646,450	22
							23

NOTES (Continued)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Taxes - FAS 109	72,104,000	4111000	11,898,000	76,516	60,282,516
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Deferred Cap Revenue 01/03 - 12/03	9,395,830	5572001	9,395,830		
6						
7	Deferred Cap Revenue 01/04 - 12/04		5572001	2,111,179	9,772,572	7,661,393
8						
9	Deferred Fuel Revenue 01/04 - 12/04		5572002	6,839,553	6,839,553	
10						
11	Auctioned S02 Allowance	1,707,393			690,427	2,397,820
12						
13	ARO Nuclear Decom Trust Unr Gains	105,415,843	1289191	35,874,835	29,316,528	98,857,536
14	ARO SFAS 143 Nuclear Decom	7,923,326	4073002	11,779,792	29,609,955	25,753,489
15						
16	Derivative Liability - MTM Oil				2,400,444	2,400,444
17						
18	OPEBS Liability - Wholesale	20,203	9260001	20,203		
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	196,566,595		77,919,392	78,705,995	197,353,198

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. 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.
4. If increases or decreases from previous period (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 Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,806,251,665	1,691,228,328
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	853,365,829	740,412,983
5	Large (or Ind.) (See Instr. 4)	253,958,706	218,648,600
6	(444) Public Street and Highway Lighting	1,491,794	1,303,566
7	(445) Other Sales to Public Authorities	209,034,575	179,215,536
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,124,102,569	2,830,809,013
11	(447) Sales for Resale	268,335,401	228,334,215
12	TOTAL Sales of Electricity	3,392,437,970	3,059,143,228
13	(Less) (449.1) Provision for Rate Refunds	11,269,477	36,332,666
14	TOTAL Revenues Net of Prov. for Refunds	3,381,168,493	3,022,810,562
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,582,058	8,388,053
17	(451) Miscellaneous Service Revenues	22,416,292	20,647,127
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	62,537,903	56,020,586
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	51,927,645	32,966,852
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	145,463,898	118,022,618
27	TOTAL Electric Operating Revenues	3,526,632,391	3,140,833,180

ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
19,347,267	19,428,943	1,364,676	1,331,914	2
				3
11,733,536	11,552,967	158,780	154,294	4
4,068,627	4,000,559	2,733	2,643	5
27,927	28,629	1,856	1,917	6
3,015,746	2,945,604	20,557	19,726	7
				8
				9
38,193,103	37,956,702	1,548,602	1,510,494	10
5,100,847	4,322,616	25	22	11
43,293,950	42,279,318	1,548,627	1,510,516	12
				13
43,293,950	42,279,318	1,548,627	1,510,516	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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	19,347,267	1,806,251,665	1,364,676	14,177	0.0934
2						
3	COMMERCIAL & IND SERVICE	15,802,163	1,107,324,535	161,513	97,838	0.0701
4						
5	PUBLIC STREET AND HIGHWAY					
6	LIGHTING	27,927	1,491,794	1,856	15,047	0.0534
7						
8	OTHER SALES TO PUBLIC					
9	AUTHORITIES	3,015,746	209,034,575	20,557	146,702	0.0693
10						
11	TOTAL SALES TO ULTIMATE	38,193,103	3,124,102,569	1,548,602	24,663	0.0818
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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	REQUIREMENT SERVICE					
2	CITY OF BARTOW	RQ	TARIFF NO. 9	55	55	55
3	CITY OF CHATTAHOOCHEE	RQ	FERC NO. 126	6	6	6
4	CITY OF HOMESTEAD	RQ	TARIFF NO. 9	15	15	15
5	CITY OF KISSIMMEE	RQ	FERC NO. 120	0	0	0
6	CITY OF MOUNT DORA	RQ	FERC NO. 127	19	19	19
7	CITY OF NEWBERRY	RQ	FERC NO. 116	6	6	6
8	CITY OF NEW SMYRNA BEACH	RQ	FERC NO. 144	43	43	43
9	CITY OF QUINCY	RQ	TARIFF NO. 1	19	19	19
10	CITY OF ST CLOUD	RQ	FERC NO. 121	0	0	0
11	CITY OF TALLAHASSEE	RQ	FERC NO. 178	27	27	27
12	CITY OF WILLISTON	RQ	FERC NO. 124	6	6	6
13	FLORIDA MUNICIPAL POWER AGENCY	RQ	FERC NO. 107	19	19	14
14	FLORIDA POWER AND LIGHT	RQ	TARIFF No. 9	200	200	200
	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.
					1
290,681	6,278,094	9,089,733	18,720	15,386,547	2
34,576	668,829	1,253,995	3,168	1,925,992	3
131,760	2,520,000	3,314,007		5,834,007	4
			8,004	8,004	5
96,582	2,139,734	3,636,693	3,168	5,779,595	6
28,655	669,477	1,244,251	3,168	1,916,896	7
253,227	3,231,720	9,419,678	996	12,652,394	8
112,336	2,177,309	4,241,937	6,336	6,425,582	9
			996	996	10
178,698	947,625	7,236,008		8,183,633	11
31,870	670,372	1,238,043	3,168	1,911,583	12
123,360	3,096,044	4,450,559	71,040	7,617,643	13
1,396,025	24,054,000	37,050,923		61,104,923	14
4,301,091	78,580,550	156,015,308	548,823	235,144,681	
799,756	0	33,945,901	-755,181	33,190,720	
5,100,847	**78,580,550**	**189,961,209**	**-206,358**	**268,335,401**	

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 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	REEDY CREEK IMPROVEMENT DISTRICT	RQ	FERC NO. 118	0	0	0
2	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	FERC NO. 106	426	426	426
3	SOUTHEASTERN POWER ADMIN	RQ	FERC NO. 65	14	14	14
4	TAMPA ELECTRIC COMPANY	RQ	FERC NO. 7	150	150	150
5						
6						
7						
8	NON-REQUIREMENTS SERVICE					
9	ALABAMA ELECTRIC CO-OP (1)	OS	FERC NO. 148	N/A	N/A	N/A
10	AMERICAN ELECTRIC POWER CO (1)	OS	FERC NO. 9	N/A	N/A	N/A
11	COBB ELECTRIC MEMBERSHIP CORP (1)	OS	FERC NO. 10	N/A	N/A	N/A
12	CARGILL-ALLIANT (1)	OS	FERC NO. 8	N/A	N/A	N/A
13	DUKE ENERGY TRADING & MKTG INC (1)	OS	FERC NO. 6	N/A	N/A	N/A
14	DTE ENERGY TRADING (1)	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**

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.
			27,663	27,663	1
1,090,982	27,927,192	52,446,428	402,396	80,776,016	2
8,176	150,154	225,094		375,248	3
524,163	4,050,000	21,167,959		25,217,959	4
					5
					6
					7
					8
1,650		57,737		57,737	9
383		23,226		23,226	10
50,588		2,053,924		2,053,924	11
19,180		789,783		789,783	12
1,769		107,234		107,234	13
52		2,153		2,153	14
4,301,091	78,580,550	156,015,308	548,823	235,144,681	
799,756	0	33,945,901	-755,181	33,190,720	
5,100,847	**78,580,550**	**189,961,209**	**-206,358**	**268,335,401**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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 POWER COMPANY (1)	OS	FERC NO. 10	N/A	N/A	N/A
2	ENTERGY-KOCH TRADING, LP (1)	OS	FERC NO. 8	N/A	N/A	N/A
3	FLORIDA MUNICIPAL POWER AGENCY (1)	OS	FERC NO. 105	N/A	N/A	N/A
4	FLORIDA POWER & LIGHT CO (1)	OS	FERC NO. 81/02	N/A	N/A	N/A
5	GAINESVILLE REGIONAL UTILITIES (1)	OS	FERC NO. 88	N/A	N/A	N/A
6	HOMESTEAD, CITY OF (1)	OS	FERC NO. 82	N/A	N/A	N/A
7	LAKELAND, CITY OF (1)	OS	FERC NO 92	N/A	N/A	N/A
8	L.G.& E. POWER ENERGY MKTG (1)	OS	FERC NO. 157	N/A	N/A	N/A
9	MORGAN STANLEY CAPITAL GROUP (1)	OS	FERC NO. 177	N/A	N/A	N/A
10	NC ELECTRIC MEMBERSHIP	OS	FERC NO. 10	N/A	N/A	N/A
11	NEW SMYRNA BEACH, CITY OF (1)	OS	FERC NO. 104	N/A	N/A	N/A
12	OGLETHORPE (1)	OS	FERC NO. 139	N/A	N/A	N/A
13	ORLANDO UTILITIES COMMISSION (1)	OS	FERC NO. 86	N/A	N/A	N/A
14	PJM INTERCONNECTION, LLC (1)	OS	PJM	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.
2,150		27,243		27,243	1
110		4,855		4,855	2
11,745		466,551		466,551	3
7,343		253,810		253,810	4
		-75		-75	5
2,543		142,271		142,271	6
1,100		39,287		39,287	7
16,980		825,194		825,194	8
421		19,298		19,298	9
408		8,460		8,460	10
2,022		224,273	-235,181	-10,908	11
76,241		2,763,955		2,763,955	12
23,150		757,812		757,812	13
8,118		415,562		415,562	14
4,301,091	78,580,550	156,015,308	548,823	235,144,681	
799,756	0	33,945,901	-755,181	33,190,720	
5,100,847	**78,580,550**	**189,961,209**	**-206,358**	**268,335,401**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	SOUTH CAROLINA ELEC & GAS CO (1)	OS	FERC NO. 8/10	N/A	N/A	N/A
3	SEMINOLE ELECTRIC COOP INC. (1)	OS	FERC NO. 128	N/A	N/A	N/A
4	SOUTHERN COMPANY FLORIDA, LLC (1)	OS	FERC NO. 10	N/A	N/A	N/A
5	SOUTHERN COMPANY SERVICES (1)	OS	FERC NO. 111	N/A	N/A	N/A
6	TALLAHASSEE, CITY OF (2)	OS	FERC NO. 122	N/A	N/A	N/A
7	THE ENERGY AUTHORITY (1)	OS	FERC NO. 175	N/A	N/A	N/A
8	TAMPA ELECTRIC CO (1)	OS	FERC NO. 80	N/A	N/A	N/A
9	TENNESSEE VALLEY AUTHORITY (1)	OS	FERC NO. 138	N/A	N/A	N/A
10						
11						
12						
13						
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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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,line 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.
11,750		312,929		312,929	1
340		11,171		11,171	2
172,717		7,455,641		7,455,641	3
25		1,150		1,150	4
170,628		6,628,400		6,628,400	5
7,574		1,159,047	-520,000	639,047	6
48,313		2,120,841		2,120,841	7
121,262		5,414,882		5,414,882	8
41,194		1,859,287		1,859,287	9
					10
					11
					12
					13
					14
4,301,091	78,580,550	156,015,308	548,823	235,144,681	
799,756	0	33,945,901	-755,181	33,190,720	
5,100,847	**78,580,550**	**189,961,209**	**-206,358**	**268,335,401**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2004	2004/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 2 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 3 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 5 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 6 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 7 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 8 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 9 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 10 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 12 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310 Line No.: 13 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310.1 Line No.: 1 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310.1 Line No.: 2 Column: j

Column J consists of Customer and/or Facility charge

Schedule Page: 310.1 Line No.: 8 Column: a

Non-requirement Service is either:

(1) Economy Interchanges Sales for
pages 310.1 lines 9-14,
pages 310.2 lines 1-14,
pages 310.3 lines 1-5 and 7-9

(2) Economy and Emergency Sales for
pages 310.3 line 6

Schedule Page: 310.2 Line No.: 11 Column: j

2004 OS Sales for City of New Smyrna Beach includes ($235,181) capacity credit.

Schedule Page: 310.3 Line No.: 6 Column: j

2004 OS Sales for City of Tallahassee includes ($520,000) for a capacity credit.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	1,638,299	1,475,385
5	(501) Fuel	658,062,830	670,920,726
6	(502) Steam Expenses	8,605,612	7,612,276
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,377	262
10	(506) Miscellaneous Steam Power Expenses	23,736,541	22,165,759
11	(507) Rents		
12	(509) Allowances	15,238,599	7,472,794
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	707,283,258	709,647,202
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,463,905	3,147,990
16	(511) Maintenance of Structures	1,436,117	1,436,815
17	(512) Maintenance of Boiler Plant	5,669,657	4,721,341
18	(513) Maintenance of Electric Plant	4,459,967	5,093,981
19	(514) Maintenance of Miscellaneous Steam Plant	27,762,455	28,083,021
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	42,792,101	42,483,148
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	750,075,359	752,130,350
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	6,245	136,291
25	(518) Fuel	33,969,862	31,099,846
26	(519) Coolants and Water	2,681,868	2,872,185
27	(520) Steam Expenses	9,274,582	10,832,476
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	3,764	
31	(524) Miscellaneous Nuclear Power Expenses	31,821,923	30,564,003
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	77,758,244	75,504,801
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	11,954,981	7,442,687
36	(529) Maintenance of Structures	1,172,871	7,179,095
37	(530) Maintenance of Reactor Plant Equipment	13,057,074	11,799,427
38	(531) Maintenance of Electric Plant	2,614,233	3,425,070
39	(532) Maintenance of Miscellaneous Nuclear Plant	1,455,013	2,288,427
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	30,254,172	32,134,706
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	108,012,416	107,639,507
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	8,387,170	7,465,422
63	(547) Fuel	452,395,718	358,414,714
64	(548) Generation Expenses	4,222,951	3,605,291
65	(549) Miscellaneous Other Power Generation Expenses	6,551,272	5,519,822
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	471,557,111	375,005,249
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	353,726	1,027,809
70	(552) Maintenance of Structures	322,172	407,891
71	(553) Maintenance of Generating and Electric Plant	2,470,207	1,905,012
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	13,146,375	16,556,866
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	16,292,480	19,897,578
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	487,849,591	394,902,827
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	568,665,170	551,700,391
77	(556) System Control and Load Dispatching	5,065,817	4,889,040
78	(557) Other Expenses	23,498	
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	573,754,485	556,589,431
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,919,691,851	1,811,262,115
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,606,417	2,599,592
84	(561) Load Dispatching	380,979	338,664
85	(562) Station Expenses	182,772	159,296
86	(563) Overhead Lines Expenses	312,673	52,708
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	2,759	
89	(566) Miscellaneous Transmission Expenses	12,743,948	12,831,158
90	(567) Rents	300	
91	TOTAL Operation (Enter Total of lines 83 thru 90)	16,229,848	15,981,418
92	Maintenance		
93	(568) Maintenance Supervision and Engineering		-3,764
94	(569) Maintenance of Structures	40,525	203,137
95	(570) Maintenance of Station Equipment	1,332,660	2,152,286
96	(571) Maintenance of Overhead Lines	8,376,124	8,580,863
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	736,875	745,032
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	10,486,184	11,677,554
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	26,716,032	27,658,972
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	6,612,559	5,385,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	4,081,995	2,137,262
106	(582) Station Expenses	276,504	323,753
107	(583) Overhead Line Expenses	4,711,997	3,202,161
108	(584) Underground Line Expenses	2,156	232
109	(585) Street Lighting and Signal System Expenses	5,265,171	4,212,181
110	(586) Meter Expenses	7,300,276	9,447,706
111	(587) Customer Installations Expenses	542,332	525,559
112	(588) Miscellaneous Expenses	28,592,023	30,984,970
113	(589) Rents	1,611,026	66,519
114	TOTAL Operation (Enter Total of lines 103 thru 113)	58,996,039	56,285,589
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	115,461	189,616
117	(591) Maintenance of Structures	31,305	108,994
118	(592) Maintenance of Station Equipment	1,792,763	1,419,548
119	(593) Maintenance of Overhead Lines	16,320,272	19,547,487
120	(594) Maintenance of Underground Lines	302,478	304,828
121	(595) Maintenance of Line Transformers	302,881	643,245
122	(596) Maintenance of Street Lighting and Signal Systems		639
123	(597) Maintenance of Meters	13,207	953
124	(598) Maintenance of Miscellaneous Distribution Plant	7,069,177	14,462,968
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	25,947,544	36,678,278
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	84,943,583	92,963,867
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	1,802,026	1,109,527
130	(902) Meter Reading Expenses	8,486,087	8,429,685
131	(903) Customer Records and Collection Expenses	23,707,780	22,668,540
132	(904) Uncollectible Accounts	4,977,560	4,812,023
133	(905) Miscellaneous Customer Accounts Expenses	10,474,852	10,550,102
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	49,448,305	47,569,877
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		
138	(908) Customer Assistance Expenses	60,850,845	62,811,069
139	(909) Informational and Instructional Expenses	3,031,326	2,513,239
140	(910) Miscellaneous Customer Service and Informational Expenses	240,774	102,716
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	64,122,945	65,427,024
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	10,869	5,158
145	(912) Demonstrating and Selling Expenses	1,454,044	1,410,985
146	(913) Advertising Expenses	527,422	1,589,706
147	(916) Miscellaneous Sales Expenses	247,033	1,500,491
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	2,239,368	4,506,340
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	73,601,224	54,268,380
152	(921) Office Supplies and Expenses	23,166,810	27,268,477
153	(Less) (922) Administrative Expenses Transferred-Credit		

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	28,363,031	24,452,213
156	(924) Property Insurance	10,655,759	9,766,201
157	(925) Injuries and Damages	6,879,262	7,957,680
158	(926) Employee Pensions and Benefits	34,349,838	56,558,515
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	2,358	
161	(929) (Less) Duplicate Charges-Cr.	600,454	2,708,646
162	(930.1) General Advertising Expenses	3,367,747	3,094,063
163	(930.2) Miscellaneous General Expenses	399,042	6,977,015
164	(931) Rents	7,950,036	8,946,440
165	TOTAL Operation (Enter Total of lines 151 thru 164)	188,134,653	196,580,338
166	Maintenance		
167	(935) Maintenance of General Plant	783,982	-3,973,176
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	188,918,635	192,607,162
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	2,336,080,719	2,241,995,357

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	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	AUBURNDALE POWER PARTNERS (1)	OS	COG	134	159	148
5	AUBURNDALE POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	BAY COUNTY(1)	OS	COG	8	10	9
7	BAY COUNY (1)	AD	COG	N/A	N/A	N/A
8	CARGILL FERTILIZER (1)	OS	COG	18	43	13
9	CARGILL FERTILIZER (1)	AD	COG	N/A	N/A	N/A
10	CITRUS WORLD (1)	OS	COG	N/A	N/A	N/A
11	CITRUS WORLD (1)	AD	COG	N/A	N/A	N/A
12	JEFFERSON POWER L.C. (1)	OS	COG	1	2	1
13	JEFFERSON POWER L.C. (1)	AD	COG	N/A	N/A	N/A
14	LAKE COUNTY (1)	OS	COG	10	14	10
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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.
							1
48,088				1,006,709		1,006,709	2
112				11,131		11,131	3
858,498			33,206,394	26,716,716		59,923,110	4
					-58,580	-58,580	5
72,368			2,789,930	1,600,310		4,390,240	6
					1,713	1,713	7
91,877			5,715,150	2,443,194		8,158,344	8
					-61,016	-61,016	9
82				3,995		3,995	10
-5					-250	-250	11
2,622			116,899	93,588		210,487	12
					-44,764	-44,764	13
84,575			5,305,530	1,908,211		7,213,741	14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

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	LAKE COUNTY (1)	AD	COG	N/A	N/A	N/A
2	LAKE COGEN LIMITED (1)	OS	COG	102	108	90
3	LAKE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
4	DADE COUNTY (1)	OS	COG	31	52	24
5	DADE COUNTY (1)	AD	COG	N/A	N/A	N/A
6	ORANGE COGEN LIMITED (1)	OS	COG	79	106	69
7	ORANGE COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
8	ORLANDO COGEN LIMITED (1)	OS	COG	65	86	52
9	ORLANDO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
10	PASCO COGEN LIMITED (1)	OS	COG	103	109	95
11	PASCO COGEN LIMITED (1)	AD	COG	N/A	N/A	N/A
12	PASCO COUNTY (1)	OS	COG	21	25	20
13	PASCO COUNTY (1)	AD	COG	N/A	N/A	N/A
14	PCS PHOSPHATE (1)	OS	COG	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
					2,168	2,168	1
424,670			28,803,218	14,390,881		43,194,099	2
					207,324	207,324	3
252,479			8,816,653	7,877,929		16,694,582	4
					16,298	16,298	5
458,346			24,672,877	15,047,317		39,720,194	6
					-132,467	-132,467	7
576,142			20,551,856	14,171,667		34,723,523	8
-80					-48,699	-48,699	9
547,288			36,153,844	13,219,228		49,373,072	10
					157,410	157,410	11
183,951			9,570,760	4,159,619		13,730,379	12
					4,133	4,133	13
1,346				70,704		70,704	14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

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	PCS PHOSPHATE (1)	AD	COG	N/A	N/A	N/A
2	PINELLAS COUNTY (1)	OS	COG	53	69	60
3	PINELLAS COUNTY (1)	AD	COG	N/A	N/A	N/A
4	POLK POWER PARTNERS (1)	OS	COG	103	116	73
5	POLK POWER PARTNERS (1)	AD	COG	N/A	N/A	N/A
6	TIMBER ENERGY RESOURCES (1)	OS	COG	9	13	10
7	TIMBER ENERGY RESOURCES (1)	AD	COG	N/A	N/A	N/A
8	US AGRI-CHEMICALS CORPORATION (1)	OS	COG	5	14	4
9	US AGRI-CHEMICALS CORPORATION (1)	AD	COG	N/A	N/A	N/A
10	RIDGE GENERATING STATION (1)	OS	COG	35	41	26
11	RIDGE GENERATING STATION (1)	AD	COG	N/A	N/A	N/A
12	INTERCHANGE POWER:					
13	AMERICAN ELECTRIC POWER CO.	OS		N/A	N/A	N/A
14	CARGILL-ALLIANT, LLC	OS		N/A	N/A	N/A
	Total					

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)	
-94					-4,270	-4,270	1
465,553			22,782,570	10,299,488		33,082,058	2
					10,104	10,104	3
412,933			37,567,489	8,516,494		46,083,983	4
					456,153	456,153	5
28,198			567,577	493,465		1,061,042	6
					-9,323	-9,323	7
41,064			548,844	1,931,363		2,480,207	8
					-22,960	-22,960	9
183,008			9,313,965	5,740,554		15,054,519	10
					-36,154	-36,154	11
							12
106				34,975		34,975	13
10,780				732,033		732,033	14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	CHATTAHOOCHEE, CITY OF	OS		N/A	N/A	N/A
2	COBB ELECTRIC MEMBERSHIP CORP.	OS		N/A	N/A	N/A
3	CAROLINA PWR. & LIGHT CO.	OS	FERC NO. 5	N/A	N/A	N/A
4	CAROLINA PWR. & LIGHT CO.	AD	FERC NO. 5	N/A	N/A	N/A
5	CALPINE ENERGY SVCS., L.P.	OS	FERC NO. 170	N/A	N/A	N/A
6	DUKE POWER COMPANY	OS	FERC NO. 110	N/A	N/A	N/A
7	FLORIDA POWER & LIGHT CO.	OS	FERC NO. 81	N/A	N/A	N/A
8	FLORIDA POWER & LIGHT CO.	AD	FERC NO. 81	N/A	N/A	N/A
9	GEORGIA POWER	OS		N/A	N/A	N/A
10	GEORGIA TRANSMISSION CORP	OS		N/A	N/A	N/A
11	HOMESTEAD, CITY OF	OS	FERC NO. 82	N/A	N/A	N/A
12	JACKSONVILLE ELECTRIC AUTHORITY	OS	FERC NO. 91	N/A	N/A	N/A
13	JACKSONVILLE ELECTRIC AUTHORITY	AD	FERC NO. 91	N/A	N/A	N/A
14	LAKELAND, CITY OF	OS	FERC NO. 92	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	
			143,032			143,032	1
145,785				8,172,698		8,172,698	2
				13,408		13,408	3
					-210	-210	4
25,358				1,608,807		1,608,807	5
206				15,052		15,052	6
51,515				3,260,624		3,260,624	7
					-671	-671	8
505				74,612		74,612	9
				15,754		15,754	10
96				8,040		8,040	11
				2,468,628		2,468,628	12
					5,651	5,651	13
42,960				3,157,001		3,157,001	14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	L.G. & E. POWER MKTG	OS	FERC NO. 157	N/A	N/A	N/A
2	MUNICIPAL ELEC. AUTHORITY OF GA	OS		N/A	N/A	N/A
3	NEW HOPE POWER PARTNERSHIP	OS		N/A	N/A	N/A
4	NEW SMYRNA BEACH, CITY OF	OS	FERC NO. 104	N/A	N/A	N/A
5	OGLETHORPE POWER CORP	OS	FERC NO. 139	N/A	N/A	N/A
6	ORLANDO UTILITIES COMMISSION	OS	FERC NO. 86	N/A	N/A	N/A
7	PJM INTERCONNECTION, LLC	OS		N/A	N/A	N/A
8	REEDY CREEK UTILITIES	OS	FERC NO. 119	N/A	N/A	N/A
9	RELIANT ENERGY SERVICES INC.	OS	FERC NO. 167	N/A	N/A	N/A
10	SEMINOLE ELECTRIC COOP INC.	OS	FERC NO. 128	N/A	N/A	N/A
11	SOUTHERN COMPANY SERVICES INC.	OS	FERC NO. 111	N/A	N/A	N/A
12	SOUTHERN COMPANY SERVICES INC.	AD	FERC NO. 70	N/A	N/A	N/A
13	SOUTHERN COMPANY SERVICES INC.	LF	FERC NO. 70	414	414	N/A
14	TALLAHASSEE, CITY OF	OS	FERC NO. 122	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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.
43,941				1,893,034		1,893,034	1
				838		838	2
4,203				288,260		288,260	3
				-324	-235,181	-235,505	4
2,215				87,560		87,560	5
69,560				5,008,080		5,008,080	6
1,632				57,945		57,945	7
7,030			300,000	414,790		714,790	8
219,428			797,900	19,314,258		20,112,158	9
75,130				4,146,276		4,146,276	10
76,948				4,407,673		4,407,673	11
-414					587,603	587,603	12
3,450,797			48,767,241	56,905,613		105,672,854	13
460				183,115	-520,000	-336,885	14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	THE ENERGY AUTHORITY	OS	FERC NO. 175	N/A	N/A	N/A
2	TAMPA ELECTRIC CO.	OS	FERC NO. 80	N/A	N/A	N/A
3	TAMPA ELECTRIC CO.	AD	FERC NO. 80	N/A	N/A	N/A
4	TAMPA ELECTRIC	LF	FERC NO. 80	60	60	N/A
5	TENNESSEE VALLEY AUTHORITY	OS		N/A	N/A	N/A
6	WESTAR ENERGY	OS	FERC NO. 168	N/A	N/A	N/A
7						
8						
9	INADVERTENT INTERCHANGE (NET)					
10						
11						
12						
13						
14						
	Total					

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)	
143,756				9,316,879		9,316,879	1
16,939				1,055,354		1,055,354	2
					11,213	11,213	3
312,660			6,786,804	12,738,644		19,525,448	4
				6,222		6,222	5
200				13,000		13,000	6
							7
							8
1,633							9
							10
							11
							12
							13
							14
9,436,450			303,278,533	265,101,412	285,225	568,665,170	

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report 2004/Q4

FOOTNOTE DATA

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 FL Public Service Commission.

* - Glades Electric Cooperative, Inc. is not regulated by FERC or the FL Public Service Commission.

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

PEF has a few retail customers located closer to the Glades system than PEF's system. As a result, it is more cost effective to serve these customers from Glades power lines rather than PEF lines. However, the customers remain PEF customers - with PEF meters and paying PEF monthly. The power these customers consume is from the Glades system and is also metered with a Glades meter. PEF pays Glades for this power every month. This makes PEF a customer of the Glades system.

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

OUT OF PERIOD ADJUSTMENT - AUBURNDALE COGENERATOR: ($58,580) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - BAY COUNTY: $1,713 ENERGY.

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

OUT OF PERIOD ADJUSTMENT - CARGILL FERTILIZER: ($61,016) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - CITRUS WORLD: (5) MWH.

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

OUT OF PERIOD AJUSTMENT - CITRUS WORLD: ($250) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - JEFFERSON POWER: ($3,297) ENERGY AND ($41,467) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - LAKE COUNTY: $2,168 ENERGY.

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

OUT OF PERIOD ADJUSTMENT - LAKE COGEN LIMITED: $175,301 ENERGY AND $32,023 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - DADE COUNTY: $76,219 ENERGY AND ($59,921) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - ORANGE COGEN LIMITED: ($132,467) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - ORLANDO COGEN LIMITED: (80) MWH.

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

OUT OF PERIOD ADJUSTMENT - ORLANDO COGEN LIMITED: ($48,699) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - PASCO COGEN LIMITED: $17,848 ENERGY AND $139,562 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - PASCO COUNTY: $4,133 ENERGY.

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

OUT OF PERIOD ADJUSTMENT - PCS PHOSPHATE: (94) MWH.

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

OUT OF PERIOD ADJUSTMENT - PCS PHOSPHATE: ($4,270) ENERGY.

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

OUT OF PERIOD ADJUSTMENT - PINELLAS COUNTY: $10,104 ENERGY.

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

OUT OF PERIOD ADJUSTMENT - POLK POWER PARTNERS: ($16,300) ENERGY AND $472,453 CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - TIMBER ENERGY RESOURCES: ($9,323) CAPACITY.

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

OUT OF PERIOD ADJUSTMENT - US AGRI-CHEMICALS CORPORATION: ($22,960) ENERGY.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2004	2004/Q4

FOOTNOTE DATA

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

OUT OF PERIOD ADJUSTMENT - RIDGE GENERATING STATION: ($57,669) ENERGY AND $21,515 CAPACITY.

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

Carolina Power & Light Co. dba Progress Energy Carolina & Florida Power Corp dba Progress Energy Florida are subsidiaries of Progress Energy.

Schedule Page: 326.3 Line No.: 4 Column: l

OUT-OF-PERIOD ADJUSTMENT OF ($210) TO ENERGY CHARGES FOR CAROLINA POWER & LIGHT CO.

Schedule Page: 326.3 Line No.: 8 Column: l

OUT-OF-PERIOD ADJUSTMENT OF ($671) TO ENERGY CHARGES FOR FLORIDA POWER & LIGHT.

Schedule Page: 326.3 Line No.: 13 Column: l

OUT-OF-PERIOD ADJUSTMENT OF $5,651 TO ENERGY CHARGES FOR JACKSONVILLE ELECTRIC AUTHORITY.

Schedule Page: 326.4 Line No.: 4 Column: l

2004 OS Purchases for City of New Smyrna Beach includes ($235,181) capacity credit.

Schedule Page: 326.4 Line No.: 12 Column: l

OUT-OF-PERIOD ADJUSTMENT OF $587,603 TO ENERGY CHARGES FOR SOUTHERN COMPANY SERVICES.

Schedule Page: 326.4 Line No.: 14 Column: l

2004 OS Purchases for City of Tallahassee includes: ($520,000) capacity credit.

Schedule Page: 326.5 Line No.: 3 Column: l

OUT-OF-PERIOD ADJUSTMENT OF $11,213 TO ENERGY CHARGES FOR TAMPA ELECTRIC.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Alabama Electric Coop	Various	Various	NF
2	American Electric Power Service	Various	Various	NF
3	Aquilla	Various	Various	AD
4	CIty of Alachua	Progress Energy Florida	City of Alachua	LFP
5	Calpine Energy Services	Various	Various	NF
6	Cargill-Alliant	Various	Various	NF
7	Central Power & Lime	Central Power & Lime	Florida Power & Light	LFP
8	Cinergy Services	Various	Various	NF
9	Cobb Electric Membership	Various	Various	NF
10	City of Homestead	Progress Energy Florida	City of Homestead	NF
11	City of Homestead	Progress Energy Florida	City of Homestead	SFP
12	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
13	City of Tallahassee	Progress Energy Florida	City of Tallahassee	LFP
14	City of Tallahassee	Various	Various	NF
15	Conoco Inc.	Various	Various	NF
16	DTE Energy Trading	Various	Various	NF
17	Duke Energy Trading & Mkting	Various	Various	NF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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 6	Various	Various				1
Tariff 6	Various	Various				2
Tariff 6	Various	Various				3
Tariff 6	Crystal River Sub	Gainesville Regional	1			4
Tariff 6	Various	Various		2,804	2,753	5
Tariff 6	Various	Various		10,932	10,702	6
Tariff 6	Brookridge Sub	FL Power & Light	135			7
Tariff 6	Various	Various		2,051	2,006	8
Tariff 6	Various	Various		716	698	9
Tariff 6	Various	FL Power & Light				10
Tariff 6	Various	FL Power & Light				11
Tariff 6	Jackson Bluff Sub	City of Tallahassee	11	24,630	24,181	12
Tariff 6	Progress Energy FL	City of Tallahassee	11			13
Tariff 6	Various	Various				14
Tariff 6	Various	Various		703	691	15
Tariff 6	Various	Various				16
Tariff 6	Various	Various		1,062	1,039	17
			925	**401,515**	**392,884**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only 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.
663			663	1
1,105			1,105	2
		-2,862	-2,862	3
7,864			7,864	4
7,985			7,985	5
35,028			35,028	6
1,917,831			1,917,831	7
6,628			6,628	8
29,510			29,510	9
169,563			169,563	10
17,895			17,895	11
152,261			152,261	12
163,202			163,202	13
482,838			482,838	14
1,843			1,843	15
181			181	16
4,184			4,184	17
41,036,958	**0**	**949,672**	**41,986,630**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Duke Power Company	Various	Various	NF
2	Dynegy Energy & Marketing	Various	Various	AD
3	Electric Clearinghouse, Inc	Various	Various	AD
4	Entergy-Koch Trading	Various	Various	NF
5	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	LFP
6	Florida Power & Light Co.	Progress Energy Florida	Florida Power & Light	SFP
7	Florida Power & Light Co.	Various	Various	NF
8	Florida Municipal Power Authority	Various	Various	OS
9	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
10	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	AD
11	Georgia Power Company	Progress Energy Florida	Georgia Power Co.	OLF
12	City of Kissimmee	Progress Energy Florida	Kissimmee Utility Authority	LFP
13	City of Lakeland	Various	Various	NF
14	City of Lakeland	Various	Various	AD
15	LG& E Energy Marketing	Various	Various	NF
16	Morgan Stanley Capital Group	Various	Various	NF
17	North Carolina Electric Membership Corp.	Various	Various	NF
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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 6	Various	Various				1
Tariff 6	Various	Various				2
Tariff 6	Various	Various				3
Tariff 6	Various	Various				4
Tariff 6	Progress Energy FL	FL Power & Light	50			5
Tariff 6	Progress Energy FL	FL Power & Light				6
Tariff 6	Various	Various				7
Tariff 6	Various	Various				8
Tariff 6	Crystal River Sub	Gainesville Regional	12			9
FERC No. 105	Intercession City Sb	Ga Power Company				10
FERC No. 105	Intercession City Sb	Ga Power Company	147			11
Tariff 6	Crystal River Sub	Kissimmee Utility	6			12
Tariff 6	Various	Various		486	476	13
Tariff 6	Various	Various				14
Tariff 6	Various	Various				15
Tariff 6	Various	Various				16
Tariff 6	Various	Various				17
			925	**401,515**	**392,884**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only 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.
2,455			2,455	1
		-3,062	-3,062	2
		97,726	97,726	3
259			259	4
715,800			715,800	5
1,241,880			1,241,880	6
779,568			779,568	7
4,670,234			4,670,234	8
59,194			59,194	9
		877,033	877,033	10
592,344			592,344	11
68,141			68,141	12
1,745			1,745	13
		-1,206	-1,206	14
10,622			10,622	15
722			722	16
664			664	17
41,036,958	**0**	**949,672**	**41,986,630**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Oglethorpe Power Corp	Various	Various	NF
2	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
3	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
4	Orlando Utilities Commission	Various	Various	NF
5	Pennsylvania New Jersey Maryland	Various	Various	NF
6	Reedy Creek Improvement Dist.	Various	Various	NF
7	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
8	Reliant Energy Services	Various	Various	AD
9	Seminole Electric Coop	Various	Various	OS
10	Seminole Electric Coop	Various	Various	NF
11	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
12	South Carolina Electric & Gas	Various	Various	NF
13	Southern Company of Florida	Various	Various	NF
14	Southern Company Services	Various	Various	NF
15	Southeastern Power Administration	Project	Preference Customers (18)	OS
16	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
17	Tampa Electric Company	Progress Energy Florida	Tampa Electric Company	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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 6	Various	Various		77	75	1
Tariff 6	Orange Sub	Tampa Electric Co	23	77,290	77,290	2
Tariff 6	Crystal River Sub	Orlando Utilities Cm	13			3
Tariff 6	Various	Various		25,577	25,035	4
	Various	Various				5
Tariff 6	Various	Various		2,014	1,983	6
Tariff 6	Hudson Sub	FL Power & Light	474			7
Tariff 6	Various	Various		30,691	30,221	8
Tariff 6	Various	Various				9
Tariff 6	Various	Various		65,781	64,352	10
Tariff 6	Progress Energy FL	Seminole Electric Co	12			11
Tariff 6	Various	Various				12
Tariff 6	Various	Various				13
Tariff 6	Various	Various		608	595	14
65	Project	Preference Customers				15
Tariff 6	Tampa Electric Co.	Ft. Meade & Wachula	23			16
Tariff 6	Progress Energy FL	Tampa Electric Co.				17
			925	**401,515**	**392,884**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only 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.
57,928			57,928	1
318,363			318,363	2
161,568			161,568	3
74,662			74,662	4
25,021			25,021	5
13,915			13,915	6
5,457,119		10,471	5,467,590	7
		-28,428	-28,428	8
19,953,479			19,953,479	9
120,817			120,817	10
189,515			189,515	11
516			516	12
20			20	13
109,387			109,387	14
340,901			340,901	15
293,478			293,478	16
1,252,650			1,252,650	17
41,036,958	**0**	**949,672**	**41,986,630**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Tampa Electric Company	Various	Various	NF
2	Tennessee Valley Authority	Various	Various	NF
3	The Energy Authority	Gainesville Regional Utilities	Gainesville Regional Utililites	LFP
4	The Energy Authority	Various	Various	SFP
5	The Energy Authority	Various	Various	NF
6	City of New Smyrna Beach	Progress Energy Florida	Utilities Commission of NSB	LFP
7	City of New Smyrna Beach	Various	Various	SFP
8	City of New Smyrna Beach	Various	Various	NF
9	Reedy Creek Improvement District	Various	Various	OS
10				
11				
12				
13				
14				
15				
16				
17				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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 6	Various	Various		7,425	7,252	1
Tariff 6	Various	Various				2
Tariff 6	Archer Sub	Gainesville Regional	2	4,442	4,411	3
Tariff 6	Various	Various		800	783	4
Tariff 6	Various	Various		142,804	137,732	5
Tariff 6	Crystal River Sub	New Smyrna Beach	5			6
Tariff 6	Various	Various		622	609	7
Tariff 6	Various	Various				8
Tariff 6	Various	Various				9
						10
						11
						12
						13
						14
						15
						16
						17
			925	**401,515**	**392,884**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only 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.
91,690			91,690	1
32,530			32,530	2
13,720			13,720	3
2,755			2,755	4
357,567			357,567	5
56,583			56,583	6
3,306			3,306	7
351,772			351,772	8
615,487			615,487	9
				10
				11
				12
				13
				14
				15
				16
				17
41,036,958	**0**	**949,672**	**41,986,630**	

Schedule Page: 328 Line No.: 3 Column: a

AD classification is the out of period adjustments for the following:

Page 328, line 3 Aquilla for ($2,862) due to a write off for an unpaid transmission invoice.

Schedule Page: 328 Line No.: 4 Column: a

LFP classifications are the long term firm contracts that will remain in effect for the contract life unless terminated by either party with written notice.

Schedule Page: 328.1 Line No.: 2 Column: a

AD classification is the out of period adjustments for the following:

Page 328.1, line 2 Dynegy ($3,062) due to a write off of an unpaid transmission invoice.

Schedule Page: 328.1 Line No.: 3 Column: a

AD classification is the out of period adjustments for the following:

Page 328.1, line 3 Electric Clearinghouse for $97,726 in order to clear a point to point transmission deposit from a Deferred Revenue account.

Schedule Page: 328.1 Line No.: 8 Column: a

OS classification is the other service contract with a term of less than one year.

Schedule Page: 328.1 Line No.: 10 Column: a

AD classification is the out of period adjustments for the following:

Page 328.1, line 10 Georgia Power for $877,033 was due to unbilled transmission for selected months during the years 2001 - 2003.

Schedule Page: 328.1 Line No.: 11 Column: a

OLF classifications are the other long term firm contracts that will remain in effect for the contract life unless terminated by either party with written notice.

Schedule Page: 328.1 Line No.: 14 Column: a

AD classification is the out of period adjustments for the following:

Page 328.1, Line 14 Lakeland Utilities for ($1,206) due to a write-off of an unpaid transmission invoice.

Schedule Page: 328.2 Line No.: 8 Column: a

AD classification is an out of period adjustment for the following:

Page 328.2, line 8 ($28,428) energy imbalance service.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Florida Power & Light	SFP	707	693	2,759			2,759
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		707	693	2,759			2,759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	419,206
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	
6	Accounting Adjustments	-5,832,575
7	Inventory Reserve	3,355,895
8	Service Company Allocations	102,758
9	Bad Debt Reserve	620,000
10	Franchise Renewal costs	1,733,758
11		
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		
42		
43		
44		
45		
46	TOTAL	399,042

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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			16,775,420		16,775,420
2	Steam Production Plant	51,883,665				51,883,665
3	Nuclear Production Plant	31,201,832	1,494,018			32,695,850
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	42,561,655				42,561,655
7	Transmission Plant	23,903,800				23,903,800
8	Distribution Plant	105,613,702				105,613,702
9	General Plant	8,835,270		33,596		8,868,866
10	Common Plant-Electric					
11	TOTAL	263,999,924	1,494,018	16,809,016		282,302,958

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%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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							
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							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 3 Column: b

Depreciation rates do not include Nuclear Decommissioning. Nuclear Decommissioning accrued in 2004 was $38,650.92 and is included in the Account 403 - Depreciation Expense.

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. Depreciation rate details are included in the 2001 report, Pages 337, 337.1, and 337.2.

No accounts appear to have changes that would warrant listing in the 2004 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Service company indirect allocations		2,358	2,358	
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
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					
42					
43					
44					
45					
46	TOTAL		2,358	2,358	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	2,358					1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							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
							42
							43
							44
							45
		2,358					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	53,869,041		
4	Transmission	8,873,572		
5	Distribution	28,045,464		
6	Customer Accounts	22,200,702		
7	Customer Service and Informational	8,300,355		
8	Sales	884,646		
9	Administrative and General	50,035,986		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	172,209,766		
11	Maintenance			
12	Production	30,487,364		
13	Transmission	1,893,739		
14	Distribution	2,016,821		
15	Administrative and General	633,323		
16	TOTAL Maint. (Total of lines 12 thru 15)	35,031,247		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	84,356,405		
19	Transmission (Enter Total of lines 4 and 13)	10,767,311		
20	Distribution (Enter Total of lines 5 and 14)	30,062,285		
21	Customer Accounts (Transcribe from line 6)	22,200,702		
22	Customer Service and Informational (Transcribe from line 7)	8,300,355		
23	Sales (Transcribe from line 8)	884,646		
24	Administrative and General (Enter Total of lines 9 and 15)	50,669,309		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	207,241,013	17,790,168	225,031,181
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/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	207,241,013	17,790,168	225,031,181
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	87,109,974		87,109,974
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	87,109,974		87,109,974
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	5,382,697	530,399	5,913,096
76	Clearing Accounts	6,653,963		6,653,963
77	Miscellaneous Deferred Debits	50,526,034		50,526,034
78	All Other Accounts	6,998,707	108,096	7,106,803
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	69,561,401	638,495	70,199,896
96	TOTAL SALARIES AND WAGES	363,912,388	18,428,663	382,341,051

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	698,957	MWH	6,408	324,336	MW Demand	893,333
2	Reactive Supply and Voltage	698,957	MWH	122,605	323,437	MW Demand	-217,037
3	Regulation and Frequency Response				17,571	MW Demand	427,412
4	Energy Imbalance				3,405	MWH	-2,873
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	1,397,914		129,013	668,749		1,100,835

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. 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 on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January	11,568	29	800	8,345	23	702	2,498		
2	February	10,286	19	800	7,388	21	702	2,175		
3	March	8,105	11	800	5,599	16	702	1,788		
4	Total for Quarter	29,959			21,332	60	2,106	6,461		
5	April	8,768	26	1700	6,373	19	777	1,599		
6	May	10,982	26	1700	8,044	22	777	2,139		
7	June	11,506	24	1700	8,519	21	777	2,189		
8	Total for Quarter	31,256			22,936	62	2,331	5,927		
9	July	12,092	14	1700	8,452	23	779	2,538	300	
10	August	11,755	31	1700	8,236	21	779	2,419	300	
11	September	11,518	2	1700	8,036	19	779	2,384	300	
12	Total for Quarter	35,365			24,724	63	2,337	7,341	900	
13	October	10,954	1	1500	7,736	20	779	2,119	300	
14	November	9,774	2	1600	6,757	19	779	1,919	300	
15	December	11,450	15	800	7,896	22	779	2,453	300	
16	Total for Quarter	32,178			22,389	61	2,337	6,491	900	
17	Total for Year to	128,758			91,381	246	9,111	26,220	1,800	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	22,149,822
4	Nuclear	6,703,023
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	7,769,454
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	36,622,299
10	Purchases	9,436,450
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	401,515
17	Delivered	392,884
18	Net Transmission for Other (Line 16 minus line 17)	8,631
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	46,067,380

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	38,193,103
23	Requirements Sales for Resale (See instruction 4, page 311.)	4,301,091
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	799,756
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	118,826
27	Total Energy Losses	2,654,604
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	46,067,380

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	3,710,770	206,924	8,748	29	800
30	February	3,231,541	141,850	7,791	19	800
31	March	3,313,153	141,938	6,017	11	800
32	April	3,300,310	124,356	6,760	26	1700
33	May	4,024,261	64,377	8,446	26	1700
34	June	4,500,916	20,141	9,125	24	1700
35	July	4,631,758	11,068	9,058	14	1700
36	August	4,440,910	9,001	8,842	31	1700
37	September	4,071,080	6,924	8,628	2	1700
38	October	3,907,747	7,907	8,324	1	1500
39	November	3,261,484	24,037	7,313	2	1600
40	December	3,673,450	41,233	8,303	15	800
41	TOTAL	46,067,380	799,756			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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			15764			22733
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			78			84
12	Net Generation, Exclusive of Plant Use - KWh			4487885000			2111619000
13	Cost of Plant: Land and Land Rights			1869309			2046939
14	Structures and Improvements			37338136			19238085
15	Equipment Costs			228796433			122966929
16	Asset Retirement Costs			0			0
17	Total Cost			268003878			144251953
18	Cost per KW of Installed Capacity (line 17/5) Including			240.9240			291.7717
19	Production Expenses: Oper, Supv, & Engr			2281			63408
20	Fuel			196888573			96079422
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			535779			315978
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			4408752			3503695
27	Rents			0			0
28	Allowances			3129014			2027413
29	Maintenance Supervision and Engineering			1266941			1159105
30	Maintenance of Structures			834535			140756
31	Maintenance of Boiler (or reactor) Plant			1193800			749892
32	Maintenance of Electric Plant			504453			407681
33	Maintenance of Misc Steam (or Nuclear) Plant			4879189			3184069
34	Total Production Expenses			213643317			107631419
35	Expenses per Net KWh			0.0476			0.0510
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	6763690	534337	0	3399088	165579	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156371	1036	0	156530	1036	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	29.116	6.529	0.000	28.175	6.725	0.000
41	Average Cost of Fuel per Unit Burned	28.635	6.529	0.000	27.916	6.725	0.000
42	Average Cost of Fuel Burned per Million BTU	4.360	6.302	0.000	4.246	6.493	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.063	0.000	0.000	0.067	0.000
44	Average BTU per KWh Net Generation	0.000	10020.000	0.000	0.000	10358.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
		15419			16832			8585	7
		0			0			0	8
		874			1467			788	9
		865			1437			769	10
		173			154			462	11
		4980485000			10168184000			6703023000	12
		3012439			0			41218	13
		74582170			149089496			219366347	14
		331854728			752544014			577897425	15
		0			0			77064813	16
		409449337			901633510			874369803	17
		424.5638			609.8299			981.8864	18
		756093			796180			6245	19
		109748528			231626745			33969862	20
		0			0			2681868	21
		3002778			4409478			9274582	22
		0			0			0	23
		0			0			0	24
		0			1377			3764	25
		3119026			10577266			31821923	26
		0			0			0	27
		4768265			5131326			0	28
		373748			400042			11954981	29
		25261			413722			1172871	30
		2004723			1627067			13057074	31
		2931797			522920			2614233	32
		10446075			7595848			1455013	33
		137176294			263101971			108012416	34
		0.0275			0.0259			0.0161	35
Oil	Coal		Oil	Coal		Oil	Nuclear		36
BBL	Tons		BBL	Tons		BBL	MMBTU		37
20865	1984593	0	120671	3910183	0	528	68741651	0	38
137930	12411	0	137998	12312	0	137807	0	0	39
45.827	52.475	0.000	50.795	56.917	0.000	34.904	0.000	0.000	40
43.038	54.801	0.000	49.463	56.730	0.000	38.741	0.354	0.000	41
7.429	2.208	0.000	8.534	2.304	0.000	6.694	0.445	0.000	42
0.074	0.000	0.000	0.081	0.000	0.000	0.000	0.005	0.000	43
9978.000	0.000	0.000	9538.000	0.000	0.000	0.000	10256.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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			11467			1575
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			401649000			58385000
13	Cost of Plant: Land and Land Rights			22059			1597635
14	Structures and Improvements			4996728			1428456
15	Equipment Costs			28596839			22306869
16	Asset Retirement Costs			0			0
17	Total Cost			33615626			25332960
18	Cost per KW of Installed Capacity (line 17/5) Including			228.6777			111.6974
19	Production Expenses: Oper, Supv, & Engr			20337			291718
20	Fuel			23719562			6247422
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			332077			187762
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			2127802			425212
27	Rents			0			0
28	Allowances			182581			0
29	Maintenance Supervision and Engineering			264069			0
30	Maintenance of Structures			21843			16861
31	Maintenance of Boiler (or reactor) Plant			94175			0
32	Maintenance of Electric Plant			93116			3076
33	Maintenance of Misc Steam (or Nuclear) Plant			1657274			252573
34	Total Production Expenses			28512836			7424624
35	Expenses per Net KWh			0.0710			0.1272
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	666088	371152	0	137136	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156572	1026	0	141573	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	32.783	5.573	0.000	49.436	0.000	0.000
41	Average Cost of Fuel per Unit Burned	32.128	5.573	0.000	45.145	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.886	5.433	0.000	7.592	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.061	0.000	0.106	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	11262.000	0.000	13966.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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 Turbine	1
		Conventional			Conventional			Conventional	2
		1975			1974			1980	3
		1992			1992			1980	4
		861.40			1310.20			183.60	5
		715			1124			183	6
		9126			14355			2589	7
		0			0			0	8
		762			1206			201	9
		667			1041			164	10
		21			25			2	11
		425913000			782222000			109066000	12
		2113330			746305			0	13
		9646483			15007505			1471200	14
		143903923			229918579			27205953	15
		0			0			0	16
		155663736			245672389			28677153	17
		180.7102			187.5075			156.1936	18
		1958559			1969925			402242	19
		39236251			72337511			10855545	20
		0			0			0	21
		225368			131862			27002	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		908531			1909640			205484	26
		0			0			0	27
		0			0			0	28
		0			287653			0	29
		76925			0			-445	30
		0			0			0	31
		11968			5892			238284	32
		1465032			2160871			226226	33
		43882634			78803354			11954338	34
		0.1030			0.1007			0.1096	35
Oil	Gas		Oil	Gas		Oil	Gas		36
BBL	MCF		BBL	MCF		BBL	MCF		37
204667	4611307	0	344644	8048300	0	68488	1116747	0	38
137942	1038	0	138061	1030	0	138408	1028	0	39
68.205	6.319	0.000	58.823	6.845	0.000	52.395	7.019	0.000	40
48.690	6.319	0.000	49.335	6.845	0.000	42.915	7.019	0.000	41
8.404	6.088	0.000	8.508	6.644	0.000	7.382	6.829	0.000	42
0.118	0.000	0.000	0.112	0.000	0.000	0.105	0.000	0.000	43
14022.000	0.000	0.000	13156.000	0.000	0.000	14174.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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: *Bartow* (b)			Plant Name: *Turner* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
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	2525			451		
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	71093000			20176000		
13	Cost of Plant: Land and Land Rights	0			824781		
14	Structures and Improvements	1074388			1328420		
15	Equipment Costs	23188847			21408420		
16	Asset Retirement Costs	0			0		
17	Total Cost	24263235			23561621		
18	Cost per KW of Installed Capacity (line 17/5) Including	108.9014			130.1747		
19	Production Expenses: Oper, Supv, & Engr	426991			286663		
20	Fuel	7146536			2468996		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	38567			12064		
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	308518			172996		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	52238			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	3268			157641		
34	Total Production Expenses	7976118			3098360		
35	Expenses per Net KWh	0.1122			0.1536		
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	42998	851041	0	52937	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138177	1036	0	137835	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	48.085	6.330	0.000	52.369	0.000	0.000
41	Average Cost of Fuel per Unit Burned	39.125	6.330	0.000	40.600	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	6.742	6.108	0.000	7.013	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.107	0.000	0.000	0.107	0.000	0.000
44	Average BTU per KWh Net Generation	15916.000	0.000	0.000	15189.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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: *Avon Park* (d)			Plant Name: *Higgins* (e)			Plant Name: *Tiger Bay* (f)			Line No.
		Gas Turbine			Gas Turbine			Gas Turbine	1
		Conventional			Conventional			Conventional	2
		1968			1969			1995	3
		1968			1971			1995	4
		67.60			153.40			278.20	5
		58			128			215	6
		956			2060			6077	7
		0			0			0	8
		64			134			223	9
		52			122			207	10
		0			0			5	11
		22230000			50877000			1113679000	12
		67207			184271			0	13
		405755			722021			10553414	14
		8202106			17070818			68246364	15
		0			0			0	16
		8675068			17977110			78799778	17
		128.3294			117.1911			283.2487	18
		357816			191982			1832582	19
		2506349			5281312			53209072	20
		0			0			0	21
		7186			181842			46262	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		86315			172252			600762	26
		0			0			0	27
		0			0			0	28
		828			0			48789	29
		0			0			0	30
		0			0			0	31
		0			34051			347676	32
		42980			92622			1120350	33
		3001474			5954061			57205493	34
		0.1350			0.1170			0.0514	35
Oil	Gas		Oil	Gas		Gas			36
BBL	MCF		BBL	MCF		MCF			37
10340	321875	0	46	837128	0	8714715	0	0	38
137957	1036	0	137164	1036	0	1036	0	0	39
51.775	6.302	0.000	0.000	6.290	0.000	6.106	0.000	0.000	40
43.797	6.302	0.000	35.128	6.290	0.000	6.106	0.000	0.000	41
7.559	6.084	0.000	6.098	6.069	0.000	5.895	0.000	0.000	42
0.134	0.000	0.000	0.000	0.104	0.000	0.048	0.000	0.000	43
17689.000	0.000	0.000	0.000	17058.000	0.000	8104.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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 Turbine			Gas Turbine		
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	93			7459		
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	802000			342884000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	88646			6411292		
15	Equipment Costs	3035059			34464638		
16	Asset Retirement Costs	0			0		
17	Total Cost	3123705			40875930		
18	Cost per KW of Installed Capacity (line 17/5) Including	161.8500			950.6030		
19	Production Expenses: Oper, Supv, & Engr	39275			618978		
20	Fuel	117234			17529382		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5111			36564		
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	10591			213426		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			15236		
30	Maintenance of Structures	14588			211653		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			586357		
33	Maintenance of Misc Steam (or Nuclear) Plant	8247			954713		
34	Total Production Expenses	195046			20166309		
35	Expenses per Net KWh	0.2432			0.0588		
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	2647	0	0	0	3448598	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138108	0	0	0	1037	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	48.760	0.000	0.000	0.000	5.044	0.000
41	Average Cost of Fuel per Unit Burned	40.029	0.000	0.000	0.000	5.044	0.000
42	Average Cost of Fuel Burned per Million BTU	6.901	0.000	0.000	0.000	4.864	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.132	0.000	0.000	0.000	0.051	0.000
44	Average BTU per KWh Net Generation	19145.000	0.000	0.000	0.000	10429.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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 Turbine			1
Conventional			2
1999			3
2003			4
1144.60	0.00	0.00	5
1055	0	0	6
13593	0	0	7
0	0	0	8
1111	0	0	9
998	0	0	10
45	0	0	11
4772127000	0	0	12
13225753	0	0	13
54865688	0	0	14
469023834	0	0	15
0	0	0	16
537115275	0	0	17
469.2602	0.0000	0.0000	18
10439	0	0	19
235460108	0	0	20
0	0	0	21
3332883	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
1537545	0	0	26
0	0	0	27
0	0	0	28
1220	0	0	29
2590	0	0	30
0	0	0	31
1190665	0	0	32
6661852	0	0	33
248197302	0	0	34
0.0520	0.0000	0.0000	35

									Line No.
Oil	Gas								36
BBL	MCF								37
1933	33964675	0	0	0	0	0	0	0	38
133250	1029	0	0	0	0	0	0	0	39
56.166	6.896	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
38.181	6.896	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
6.822	6.699	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.050	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7329.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	3,984.83	446.63	81

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								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	497,777,935	539,626,780	312,673	8,376,124		8,688,797	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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		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)	Structure (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	3,984.83	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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	497,777,935	539,626,780	312,673	8,376,124		8,688,797	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	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	3,984.83	446.63	81

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	497,777,935	539,626,780	312,673	8,376,124		8,688,797	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	3,984.83	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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	497,777,935	539,626,780	312,673	8,376,124		8,688,797	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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				2,557.79	183.49	
13	OTHER TRANS. LINES	UNDERGROUND 115				47.29		
14								
15	Total Overhead Transmission	Line Expenses				3,984.83	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	3,984.83	446.63	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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	245,807,885	265,504,933					12
	88,132	11,739,339	11,827,471					13
								14
	41,848,845	497,777,935	539,626,780					15
				312,673	8,376,124		8,688,797	16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	41,848,845	497,777,935	539,626,780	312,673	8,376,124		8,688,797	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	CFO-19	LAKE ELLA	0.06	ST	4.00	2	2
2	TZ-485 TAP	NEW RIVER	1.37	CP	15.00	1	1
3	VFGS-48-23	FT GREEN #10	3.04	CP	15.00	1	1
4	SORRENTO (PEF)	SOR. (SECO)	0.27	CP	15.00	1	1
5	RW-64 RELOCATION	RW-68	0.13	CP	15.00	1	1
6							
7							
8							
9							
10							
11							
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							
42							
43							
44	TOTAL		4.87		64.00	6	6

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
795	AAC	V	69		150,137	64,065		214,202	1
795	AAC	V	69		1,129,484	295,621	2,495	1,427,600	2
336	ACSR	V	69		605,865	261,157	6,554	873,576	3
4/0	ACSR	V	69		83,354	27,046		110,400	4
795	AAC	V	69		103,098	32,212	-5,527	129,783	5
									6
									7
									8
									9
									10
									11
									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
									42
									43
					2,071,938	680,101	3,522	2,755,561	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	ANCLOTE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
6	BAYBORO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	BAYVIEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	BAYWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	BELLEAIR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	BROOKER CREEK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	12.00
12	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	7.00
13	BROOKSVILLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
14	BROOKSVILLE ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	2.00	
15	BUSHNELL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
16	CAMPS SECTION 7 MINE-SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
17	CENTER HILL - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
18	CENTRAL PLAZA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	CONSOLIDATED ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
21	CROSS BAYOU - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	CROSSROADS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	CURLEW - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	DENHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
26	DISSTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	DUNEDIN - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
28	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	14.00
29	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	240.00	120.00	
30	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
31	EAST CLEARWATER - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	ELFERS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	FLORAL CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	FLORA-MAR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	FLORIDA ROCK - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
36	G.E. PINELLAS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	GATEWAY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	115.00	4.00	
39	HAMMOCK - SUNCOAST FLORDAI REGION	DIST - UNATTENDED	67.00	4.00	
40	HIGHLANDS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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
60	2					6
100	2					7
40	1					8
80	2					9
60	2					10
150	1					11
100	1					12
60	2					13
9	1	1				14
13	1					15
19	2	1				16
13	1	1				17
60	2					18
120	4					19
2	1	1				20
150	3					21
80	2					22
90	3					23
90	3					24
150	1					25
80	2					26
60	3					27
200	1					28
200	1					29
250	1					30
150	3					31
100	2					32
13	1					33
100	2					34
12	2	2				35
29	2					36
90	3					37
20	1					38
19	2					39
80	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	KENNETH CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
3	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	13.00
4	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	5.00
5	LARGO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	MAXIMO - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	NEW PORT RICHEY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
9	NORTHEAST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	OAKHURST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00
12	PALM HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
14	PASADENA - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	PILSBURY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	PINELLAS WELL FIELD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	66.00	3.00	
17	PORT RICHEY WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	SAFETY HARBOR - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
19	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
20	SEMINOLE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
21	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
22	SEVEN SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
23	SIXTEENTH ST. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	STARKEY ROAD - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	TANGERINE - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
26	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	
27	TARPON SPRINGS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	TAYLOR AVE. - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	TRI-CITY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
30	TRILBY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
31	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
32	ULMERTON - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
33	ULMERTON WEST - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
34	VINOY - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
35	WALSINGHAM - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	ZEPHYRHILLS - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
37	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
38	ZEPHYRHILLS NORTH - SUNCOAST FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
39					
40					

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
200	1					2
200	1					3
200	1					4
100	2					5
150	3					6
60	2					7
400	2					8
100	2					9
90	3					10
250	1					11
60	2					12
250	1					13
80	2					14
100	2					15
5	1	1				16
90	3					17
80	2					18
250	1					19
100	2					20
60	2					21
750	3					22
80	2					23
80	2					24
60	2					25
150	1					26
100	2					27
80	2					28
60	2					29
9	1	1				30
450	2					31
100	2					32
80	2					33
100	2					34
100	2					35
60	2					36
250	1					37
60	2					38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	APALACHICOLA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
4	ARCHER - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
5	BEACON HILL - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
6	CARRABELLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
7	CARRABELLE BEACH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
8	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
9	CRAWFORDVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	CROSS CITY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	EAST POINT - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	FOLEY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
14	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	67.00	4.00
15	FORT WHITE - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
16	G.E. ALACHUA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	GAINESVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	25.00	
18	GEORGIA PACIFIC - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
19	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
20	HIGH SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	7.00	
21	HULL ROAD - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	INDIAN PASS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
23	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
24	JASPER - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
25	JENNINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
26	LURAVILLE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
27	MADISON - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	MONTICELLO - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
29	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
30	NEWBERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	12.00	
31	O'BRIEN - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
32	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
33	OCCIDENTAL #1 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
34	OCCIDENTAL #2 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
35	OCCIDENTAL #3 - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
36	OCCIDENTAL SWIFT CREEK#1-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
37	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
38	OCCIDENTAL SWIFT CREEK#2-NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	OCHLOCKONEE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	14.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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.
13	1	1				1
13	1	1				2
150	1					3
16	2	2				4
13	1	1				5
13	1	1				6
2	1	1				7
100	1					8
13	1	1				9
13	1	1				10
13	1	1				11
40	2					12
100	1					13
75	1					14
6	1	1				15
20	1					16
30	1					17
10	1	1				18
9	1					19
13	1	1				20
19	2					21
5	1	1				22
60	1					23
13	1	1				24
2	1	1				25
9	1	1				26
40	2					27
40	2					28
100	1					29
13	1	1				30
6	1	1				31
13	1					32
25	1					33
40	2					34
13	1					35
60	3					36
20	1					37
30	1					38
9	1	1				39
250	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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	PERRY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	PERRY NORTH - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
3	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	
4	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
5	PORT ST. JOE - NORTH FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
6	RIVER JUNCTION - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	SHAMROCK - NORTH FLORIDA REGION	DIST - UNATTENDED	12.00	4.00	
8	SOPCHOPPY - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	ST. GEORGE ISLAND - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
10	ST. MARKS - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
11	SUTTERS CREEK - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	TRENTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	UNIVERSITY OF FLORIDA - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	23.00	
14	WAUKEENAH - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	WHITE SPRINGS - NORTH FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	WILLISTON - NORTH FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
17	WILLISTON TOWN - NORTH FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18					
19	ADAMS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	ALAFAYA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
22	ALTAMONTE SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	APOPKA SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	BARBERVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	BAY RIDGE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	BELLEVIEW - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	BEVERLY HILLS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
28	CASSADAGA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
29	CASSELBERRY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	CIRCLE SQUARE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	CITRUS HILL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
32	CLARCONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	CLERMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	COLEMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	CRYSTAL RIVER NORTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
36	CRYSTAL RIVER SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
37	DELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	DELAND EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
39	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	
40	DELTONA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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.
40	2					1
20	1					2
100	1					3
20	1					4
200	2					5
19	1	1				6
2	1	1				7
9	1	1				8
20	1					9
13	1	1				10
19	2					11
13	1	1				12
90	3					13
9	1					14
2	1	1				15
13	1	1				16
9	1					17
						18
20	1					19
60	2					20
200	1					21
100	2					22
90	3					23
40	2					24
40	2					25
40	2					26
60	2					27
60	2					28
120	3					29
19	2					30
20	1					31
90	3					32
60	2					33
29	2					34
19	1	1				35
9	1	1				36
100	2					37
90	3					38
75	1					39
120	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	DELTONA EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
2	DOUGLAS AVENUE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	DUNNELLON TOWN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	EAGLENEST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	EATONVILLE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	ECON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
7	EUSTIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	EUSTIS SOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
9	FERN PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
10	GROVELAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	116.00	
12	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
13	HOLDER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
14	HOMOSASSA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
15	HOWEY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	
17	INGLIS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
19	INVERNESS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	KELLER ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	KELLY PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LADY LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23	LAKE ALOMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	LAKE EMMA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
25	LAKE HELEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
26	LAKE WEIR - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	LEBANON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
28	LIBSON - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	LOCKHART - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
30	LOCKWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	MAITLAND - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	MARICAMP - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	MARTIN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	MCINTOSH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	MINNEOLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
37	MONTEVERDE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
38	MOUNT DORA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	MYRTLE LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
40	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	

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
40	2					3
19	2					4
90	3					5
100	2					6
60	2					7
63	2					8
30	1					9
19	2					10
250	1					11
250	1					12
19	2					13
20	1					14
13	1	1				15
100	1					16
9	1					17
160	2					18
60	2					19
60	2					20
9	1					21
29	2					22
100	2					23
100	2					24
55	2					25
19	2					26
5	1	1				27
40	2					28
100	2					29
30	1					30
40	2					31
90	3					32
19	2					33
20	1					34
9	1					35
20	1					36
40	2					37
40	2					38
100	2					39
250	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	NORTH LONGWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
2	OCOEE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	OKAHUMPKA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	ORANGE BLOSSOM - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	115.00	14.00
6	ORANGE CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
7	OVIEDO - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
9	PIEDMONT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	PLYMOUTH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
12	RAINBOW SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	REDDICK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	SANTOS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
16	SILVER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	SILVER SPRINGS SHORES-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	SPRING LAKE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	TROPIC TERRACE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
20	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	7.00
21	TURNER PLANT - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	110.00	13.00	
23	TWIN COUNTY RANCH - NORTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	13.00	
24	UNIV OF CENTRAL FL - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	UNIV OF CNTL FL NORTH-NORTH CNTL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	UMATILLA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	WEIRSDALE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
28	WEKIVA - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
29	WELCH ROAD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
30	WEST CHAPMAN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	WILDWOOD CITY - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	WINTER GARDEN - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	WINTER GARDEN CITRUS-NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
35	WINTER GARDEN CITRUS#2-NORTH CENTRAL FL REGION	DIST - UNATTENDED	12.00		
36	WINTER PARK - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
38	WINTER PARK EAST - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
39	WINTER SPRINGS - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
40	WINTER SPRINGS - NORTH CENTRAL FL 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) 12/31/2004	Year/Period of Report End of 2004/Q4

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.
100	2					1
90	3					2
40	2					3
40	2					4
250	1					5
60	2					6
90	3					7
250	1					8
100	2					9
13	1	1				10
9	1					11
19	2					12
22	2					13
13	1					14
250	1					15
20	1					16
40	2					17
90	3					18
40	2					19
160	2					20
40	2					21
13	1	1				22
9	1					23
60	2					24
60	2					25
40	2					26
19	2					27
100	2					28
100	2					29
60	2					30
25	1					31
60	2					32
9	1	1				33
1	1					34
5	4					35
120	4					36
500	2					37
100	2					38
250	1					39
90	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
2	WOODSMERE - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	ZELLWOOD - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	ZUBER - NORTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5					
6	AGRICOLA #4 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	ARBUCKLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
8	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
9	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	67.00	12.00
10	AVON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	AVON PARK NORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	BABSON PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	BARNUM CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	BAY HILL - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
15	BITHLO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	BOGGY MARSH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	BONNET CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	CABBAGE ISLAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	CANOE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	4.00
20	CELEBRATION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	CENTRAL PARK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	CHAMPIONS GATE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
23	CITRUSVILLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
24	CLEAR SPRINGS EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
25	CONWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
26	COUNTRY OAKS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	CROOKED LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
28	CURRY FORD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
29	CYPRESSWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
30	DACO - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
31	DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	DESOTO CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	DINNER LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
34	DUNDEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	EAST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	EAST ORANGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	8.00
38	FISHEATING CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	69.00	8.00
40	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	110.00	14.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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.
250	1					1
40	2					2
40	2					3
29	2					4
						5
9	1					6
8	1					7
200	1					8
150	1					9
40	2					10
40	2					11
20	1					12
19	2					13
90	3					14
50	2					15
40	2					16
60	2					17
29	2					18
30	1					19
60	2					20
90	3					21
20	1					22
20	1					23
20	1					24
40	2					25
40	2					26
10	1					27
50	1					28
40	2					29
13	1					30
20	1					31
19	2					32
75	2					33
20	1					34
19	2					35
120	3					36
150	1					37
9	1					38
60	1					39
150	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
2	FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	FOUR CORNERS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
4	FROSTPROOF - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	HAINES CITY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	HEMPLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
7	HOLOPAW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	25.00	
8	HORSE CREEK #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
9	HUNTERS CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	INTERNATIONAL DRIVE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	13.00	
11	ISLEWORTH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
13	LAKE BRYAN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	LAKE LUNTZ - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
15	LAKE MARION - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
16	LAKE OF THE HILLS - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	LAKE PLACID - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
19	LAKE WILSON - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	LAKEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
21	LEISURE LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
22	LITTLE PAYNE CREEK#1-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
23	LITTLE PAYNE CREEK#2-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	25.00	
24	MAGNOLIA RANCH - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
25	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
26	MEADOWS WOODS SOUTH-SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
27	MULBERRY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	4.00	
28	NARCOOSEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
29	NORALYN #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	12.00	
30	NORALYN #2 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
31	ORANGEWOOD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
32	PARKWAY - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
33	PEMBROKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	66.00	12.00	
34	PINECASTLE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
35	POINCIANA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
36	REEDY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
37	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	14.00
38	RIO PINAR - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
39	SAND LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
40	SAND MOUNTAIN - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
200	1					1
9	1					2
60	2					3
50	2					4
80	2					5
60	2					6
25	2					7
9	1					8
60	2					9
100	2					10
19	2					11
500	2					12
90	3					13
30	1					14
20	1					15
20	1					16
40	2					17
60	2					18
40	2					19
55	2					20
9	1					21
13	1					22
13	1					23
13	1	1				24
200	1					25
60	2					26
6	1	1				27
90	3					28
9	3	1				29
9	1	1				30
100	2					31
60	3					32
2	1	1				33
40	2					34
60	2					35
40	2					36
500	2					37
100	2					38
80	2					39
9	1	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	SEBRING EAST - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
2	SHINGLE CREEK - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
3	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
4	SKY LAKE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
5	SOUTH BARTOW - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
6	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	25.00	
7	SOUTH FORT MEADE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	115.00	4.00	
8	SUNFLOWER - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	69.00	13.00	
9	SUN'N LAKES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
10	TAFT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
11	TAUNTON RD - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
12	VINELAND - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
13	WAUCHULA - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
14	WEST DAVENPORT - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	14.00	
15	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	13.00
16	WEST LAKE WALES - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
17	WESTRIDGE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
18	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	13.00	4.00	
19	WEWAHOOTEE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
20	WHIDDEN CREEK #1 - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	4.00	
21	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	230.00	67.00	
22	WINDERMERE - SOUTH CENTRAL FL REGION	DIST - UNATTENDED	67.00	13.00	
23					
24	TOTAL DISTRIBUTION		34370.00	7504.00	360.00
25					
26	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
27	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
28	BROOKRIDGE - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	133.00	
29	BROOKSVILLE WEST - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
30	HIGGINS PLANT - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
31	HUDSON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
32	LAKE TARPON - SUNCOAST FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
33					
34	DRIFTON - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
35	GUMBAY - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
36	HAVANA - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	
37	IDYLWILD - NORTH FLORIDA REGION	TRANS - UNATTENDED	138.00	67.00	12.00
38	QUINCY - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	67.00	4.00
39	SUWANNEE 230 KV - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
40	TALLAHASSEE - NORTH FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

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.
20	1					1
60	2					2
250	1					3
90	3					4
9	1					5
19	1					6
45	2					7
30	1					8
40	2					9
60	2					10
20	1					11
60	2					12
19	2					13
19	2					14
250	1					15
13	1	1				16
20	1					17
9	1	1				18
13	1	1				19
20	1					20
200	1					21
40	2					22
						23
24570	566	51				24
						25
750	1					26
250	1					27
250	1					28
250	1					29
250	1					30
500	2					31
1500	2	1				32
						33
105	2					34
75	1					35
75	1					36
150	1					37
75	1					38
400	2					39
120	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

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	WILCOX - NORTH FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
2	ANDERSEN - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
3	BARBERVILLE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	66.00	33.00
4	CAMP LAKE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	15.00
5	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
6	CENTRAL FLORIDA - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
7	CLERMONT EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	14.00
8	CRYSTAL RIVER EAST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	116.00	
9	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
10	DELAND WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	115.00	67.00	15.00
11	HAINES CREEK - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
12	MARTIN WEST - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
13	ROSS PRAIRIE - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	69.00	
14	SORRENTO - NORTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
15					
16	BARCOLA - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
17	GRIFFIN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	115.00	13.00
18	INTERCESSION CITY - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
19	KATHLEEN - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	512.00	230.00	14.00
20	NORTH BARTOW - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	
21	VANDOLAH - SOUTH CENTRAL FL REGION	TRANS - UNATTENDED	230.00	67.00	23.00
22					
23	TOTAL TRANSMISSION		8166.00	3342.00	240.00
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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.
150	1					1
133	1					2
30	4	1				3
150	1					4
1500	2					5
450	2					6
250	1					7
250	1					8
200	1					9
125	1					10
250	1					11
200	1					12
150	1					13
250	1					14
						15
150	1					16
250	1					17
250	1					18
750	1					19
150	1					20
400	2					21
						22
10788	45	2				23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 1 Column: g

Single phase units are grouped and reported as a single transformer bank. Individual units are listed as separate line items.

Schedule Page: 426 Line No.: 14 Column: h

Spare transformers present at each substation are reported, but not included in the capacity rating of the station.

Schedule	Page No.

Florida Public Service Commission

Diversification Report

Progress Energy Florida Inc.

December 31, 2004

SIGNATURE PAGE

I certify that I am the responsible accounting officer of
PROGRESS ENERGY FLORIDA INC.
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, 2004 to December 31, 2004, 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.

4/29/05	
Date	**Signature**
Robert H. Bazemore, Jr.	Vice President & Controller
Name	**Title**

Affiliation of Officers and Directors

Company: ***Progress Energy Florida Inc.***
For the Year Ended December 31, 2004

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 exercising 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
Robert H. Bazemore, Jr	Vice President, Controller	None	
William Cavanaugh III	Director, Chairman of the Board	Board of Directors	Duke Realty Corp Indianapolis, IN
		Chairman, 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
		Director	Advanced Energy Corporation Raleigh, NC
		Director	NC State Engineering Foundation Raleigh, NC

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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 exercising 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
		Director	NC Zoological Society Asheboro, NC
		Director	Greater Triangle Regional Council Research Triangle Park, NC
		Chairman	Greater Raleigh Chamber of Commerce Raleigh, NC
		Director	Assoc. of Edison Illuminating Companies Birmingham, AL
		Director	Research Triangle Regional Partnership Raleigh, NC
		Director	Southeastern Electric Exchange Atlanta, GA
		Director / VP	Progress Energy Foundation Raleigh, NC
		Director / Exec VP	Florida Power Corporation
H. Willliam Habermeyer, Jr.	Director, President and CEO	Board Member & Vice Chair	Enterprise Florida Orlando, FL
		Board Member	Pinellas County Education Foundation Largo, FL

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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 exercising 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
		Board Member	Florida Chamber of Commerce Tallahassee, FL
		Board Member Chair	Tampa Bay Partnership Tampa, FL
		Board Member	Florida Council for Economic Education Tampa, FL
		Board Member	Eckerd College St. Petersburg, FL
		Board Member	USF St. Petersburg Campus St. Petersburg, FL
		Trustee	Salvador Dali Museum St. Petersburg, FL
		Board Member	Boys and Girls Club of the Suncoast St. Petersburg, FL
		Board Member	Museum of Fine Arts St. Petersburg, FL
		Director	Raymond James Financial, Inc St. Petersburg. FL
C.S. Hinnant	Senior Vice President & Chief Nuclear Officer	Director	Carolinas Virginia Nuclear Power Assoc. Columbia, SC

Affiliation of Officers and Directors

***Company:* Progress Energy Florida Inc.**
For the Year Ended December 31, 2004

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 exercising 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
		Vice President	Advanced Reactor Corp District of Columbia
William D. Johnson	Group President Energy Delivery	Board Member	Golden LEAF Raleigh, NC
		Board Member	Daugherty Endowment Fund Raleigh, NC
		Board Member	Triangle Opera Raleigh, NC
		Board Chair	Exploris Raleigh, NC
		Board Member	Frankie Lemmon Foundation Raleigh, NC
Jeff Lyash	Senior Vice President Chief Financial Officer	None	
John R. McArthur	Senior Vice President General Counsel & Secretary	Board of Directors	Easter Seals UCP North Carolina Raleigh, NC
Robert B. McGehee	Chairman and CEO	Board Member	WANO, Atlanta Center Atlanta, GA
		Board Member	INPO Atlanta, GA

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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 exercising 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
		Board Member	NEI Washington, D.C.
		Board Member	EEI Washington, D.C.
		Board Member	U.S. Chamber of Commerce Washington, D.C.
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
Frank A. Schiller	Vice President - Legal General Counsel	None	
Peter M. Scott III	Director, Executive Vice President	Board of Governors Vice Chair	Capital City Club Raleigh, NC

Affiliation of Officers and Directors

Company:* *Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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 exercising 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
		Director	North Carolina Museum of Art Foundation Raleigh, NC
		Board of Governors Member	RTI International Research Triangle Park, NC
Thomas R. Sullivan	Vice President, Treasurer	None	

Business Contracts with Officers, Directors and Affiliates

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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	7,000	Donation
	Pinellas County Education Foundation Largo, FL	57,500	Donation
	Florida Chamber of Commerce Tallahassee, FL	35,000	Donation
	Tampa Bay Partnership Tampa, FL	1,000	Donation
	Florida Council for Economic Education Tampa, FL	15,000	Donation
	Eckerd College St. Petersburg, FL	1,000	Donation
	USF St. Petersburg Campus St. Petersburg, FL	6,000	Donation
	Boys and Girls Club of the Suncoast St. Petersburg, FL	13,100	Donation
Robert B. McGehee	INPO Atlanta, GA	720,560	Dues
	EEI Washington D.C.	27,986	Dues
Peter M. Scott III	Capital City Club Raleigh, NC	1,437	Dues

Reconciliation of Gross Operating Revenues
Annual Report versus Regulatory Assessment Fee Return

Company: ***Progress Energy Florida Inc.*** — ***For the Year Ended December 31, 2004***

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).

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
Line No.	Description	Gross Operating Revenues per Page 300	Interstate and Sales for Resale Adjustments	Adjusted Intrastate Gross Operating Revenues	Gross Operating Revenues per RAF Return	Interstate and Sales for Resale Adjustments	Adjusted Intrastate Gross Operating Revenues	Difference (d) - (g)	
1	Total Sales to Ultimate Customers (440-446, 448)	$ 3,124,102,569	$ 41,312,983	$ 3,082,789,586	$ 3,124,102,569	$ 41,312,983	$ 3,082,789,586	$ (0)	
2	Sales for Resale (447)	268,335,400	268,335,400	-	268,335,400	268,335,400	-	-	
3	Total Sales of Electricity	3,392,437,969	309,648,383	3,082,789,586	3,392,437,969	309,648,383	3,082,789,586	(0)	
4	Provision for Rate Refunds (449.1)	(11,269,477)	(630,263)	(10,639,214)	(11,269,477)	(630,263)	(10,639,214)	(0)	
5	Total Net Sales of Electricity	3,381,168,492	309,018,120	3,072,150,372	3,381,168,492	309,018,120	3,072,150,372	(0)	
6	Total Other Operating Revenues (450-456)	145,463,898	43,879,565	101,584,333	146,049,190	43,879,564	102,169,626	(585,293)	(1)
7	Other (Specify)								
8									
9									
10	**Total Gross Operating Revenues**	$ 3,526,632,390	$ 352,897,685	$ 3,173,734,705	$ 3,527,217,682	$ 352,897,684	$ 3,174,319,998	$ (585,293)	

Notes: (1) Difference due to error on regulatory assessment fee return.

Analysis of Diversification Activity
Changes in Corporate Structure

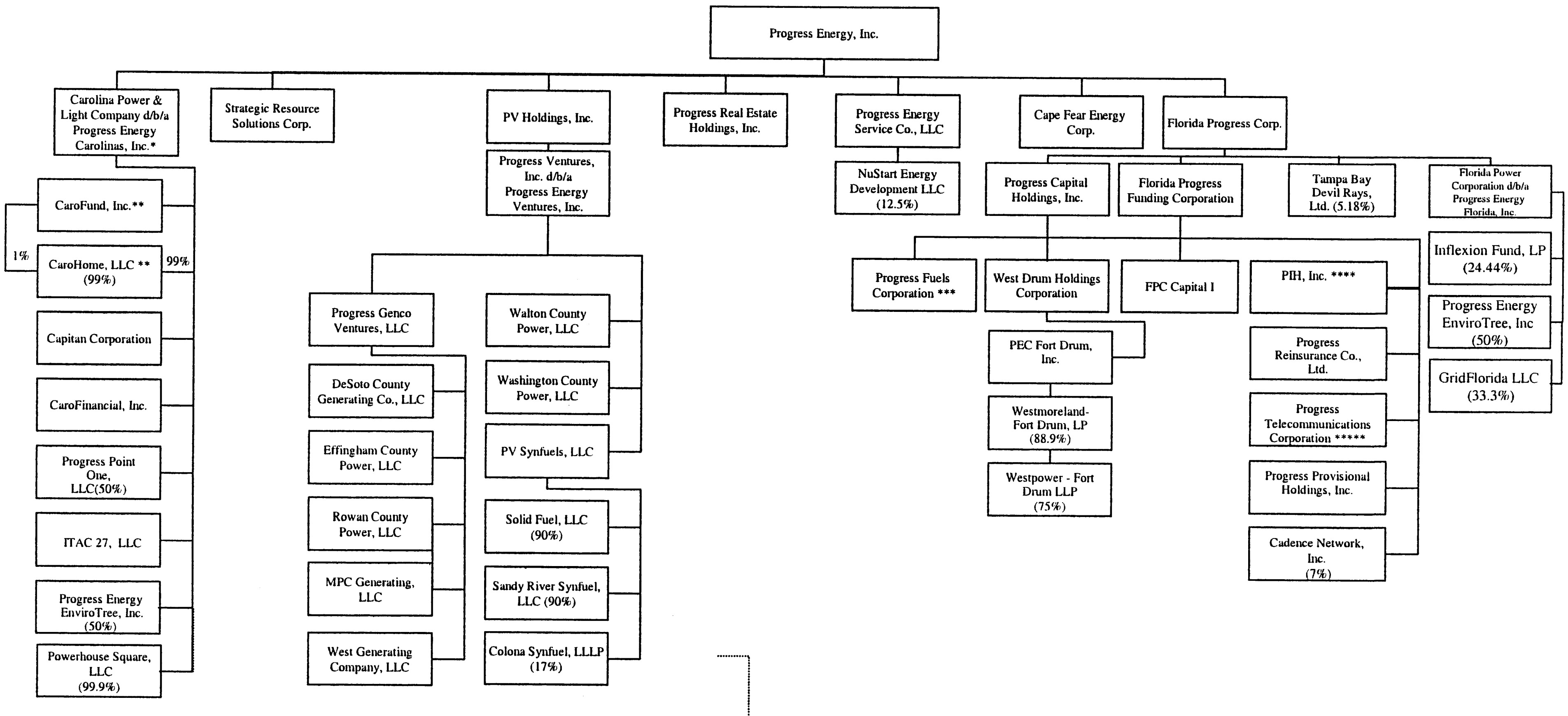
Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2004

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)
3/30/2004	Progress Energy Corporation changed its name to West Drum Holdings Corporation
4/5/2004	PEC's investment in Palmetto Seed Capital Fund LP was liquidated
4/5/2004	CaroHome, LLC sold its 99% limited partnership interest in Raleigh-CaroHome/WCK, LLC to a 3rd party
5/5/2004	CaroHome, LLC and CaroFund, Inc. sold their interests in Enston Home LP, The Garner School Apartments, LLC and Wilmington Hopper Schools Apartments LLC to a 3rd party
6/15/2004	Progress Energy Service Company, LLC acquired a 12.5% membership interest in NuStart Energy Development, LLC
6/15/2004	Kanawha River Terminals, Inc. sold 49.8% of its interest in Colona Synfuel, LLLP to 3rd parties
6/30/2004	Dixie Fuels II Limited was dissolved
7/9/2004	Progress Energy Solutions, Inc. and PES Engineering Corp. were sold to a 3rd party
7/28/2004	Railcar Finance, LLC was dissolved
7/31/2004	Winchester Energy Company, Ltd. and Progress Fuels North Texas Gas, LP were merged into Winchester Production Company, Ltd. This resulted in a change in Westchester Gas Company's and Vaughan Holding Company's relative interests in Winchester Production Company, Ltd. from 99% and 1% to 96.1% and 3.9% respectively
7/31/2004	Westchester Gas Company, Ltd. changed its name to Winchester Energy Company, Ltd.
7/31/2004	PFC Gas Holdings, LLC was created as subsidiary of Progress Fuels Corporation. Progress Fuels Corporation contributed its interest in WGC Holdco, LLC and Westchester Gas Company, Ltd. to PFC Gas Holdings, LLC.
9/9/2004	Black River Limited Partnership was dissolved
12/31/2004	FPC Del, Inc. was dissolved.
12/31/2004	Progress Holdings, Inc. was merged into its parent, Progress Capital Holdings
12/31/2004	Dissolution documents for 3079936 Nova Scotia Company have been prepared & submitted to the applicable regulatory agency in Nova Scotia

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.

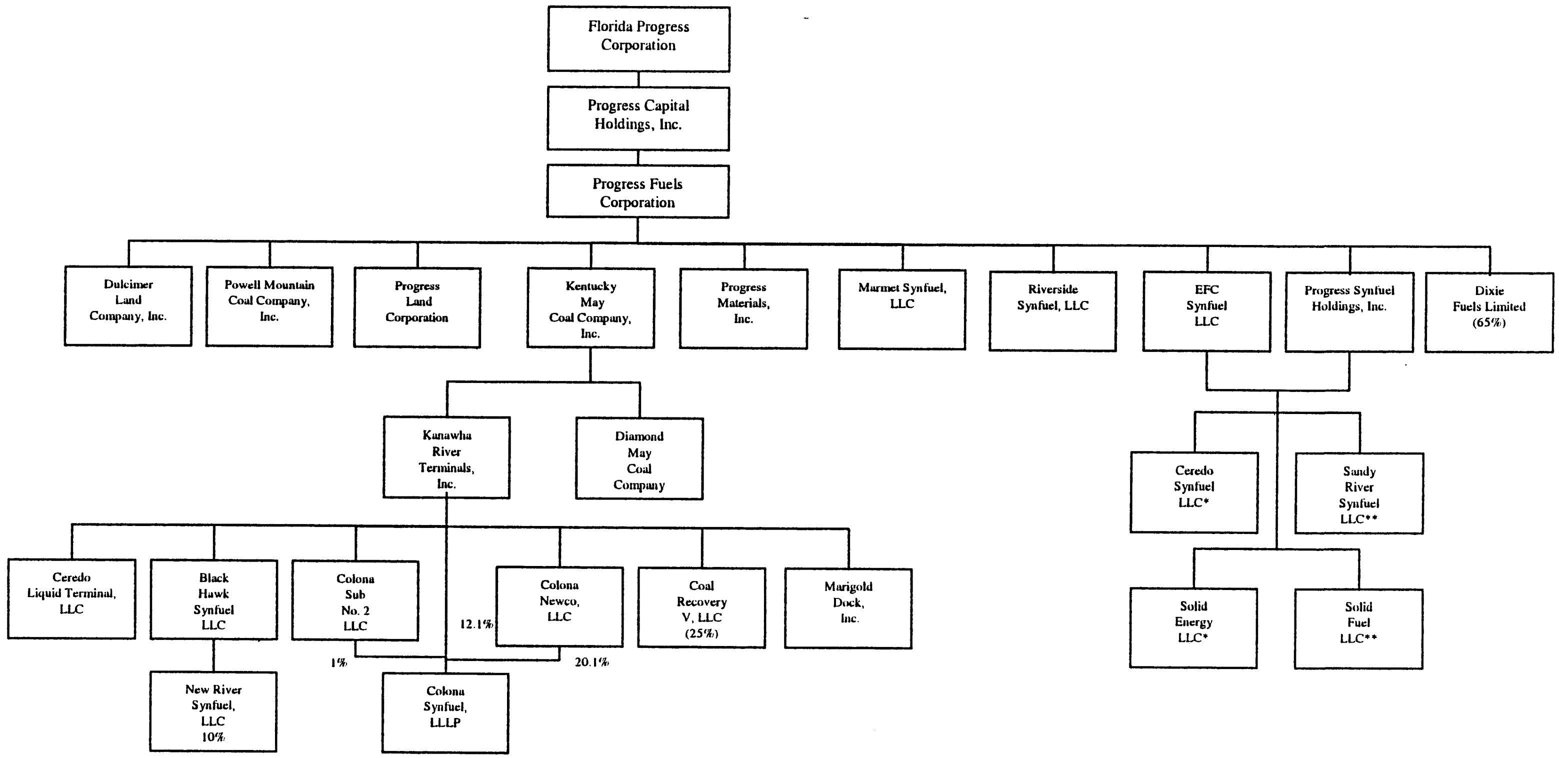
***** See Progress Telecommunications subsidiaries on page 6.

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.

12-31-04

Progress Fuels Corporation

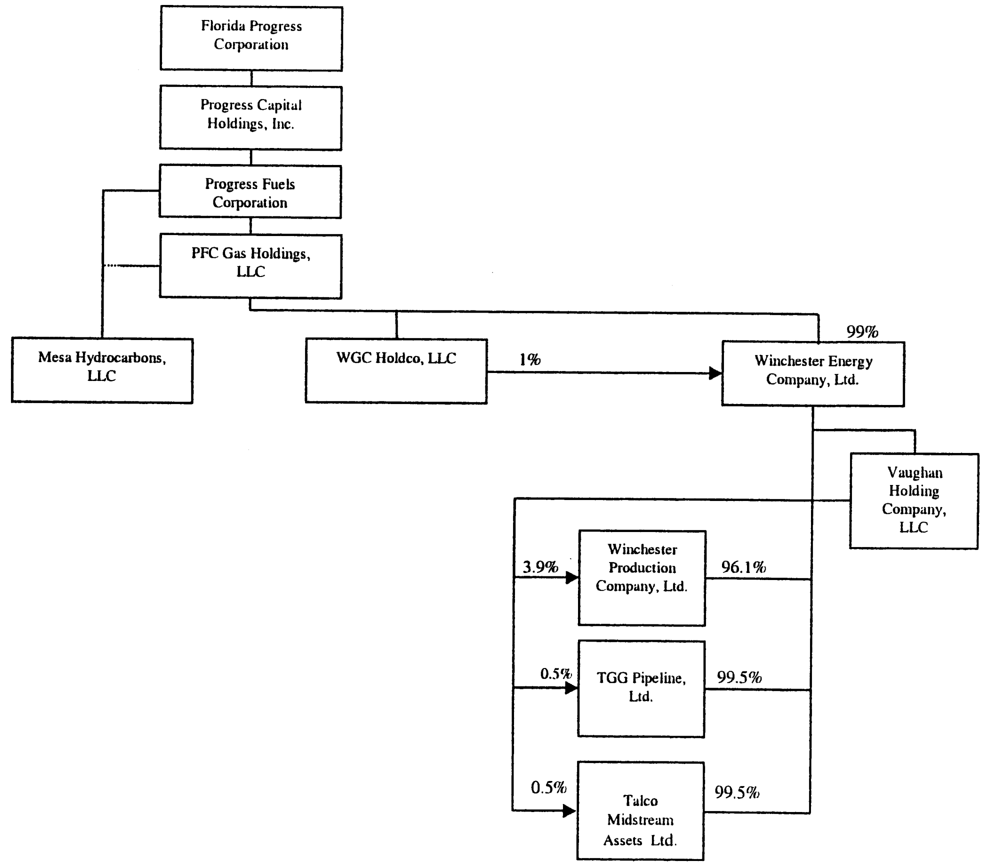
Energy & Related Services Group



* 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.

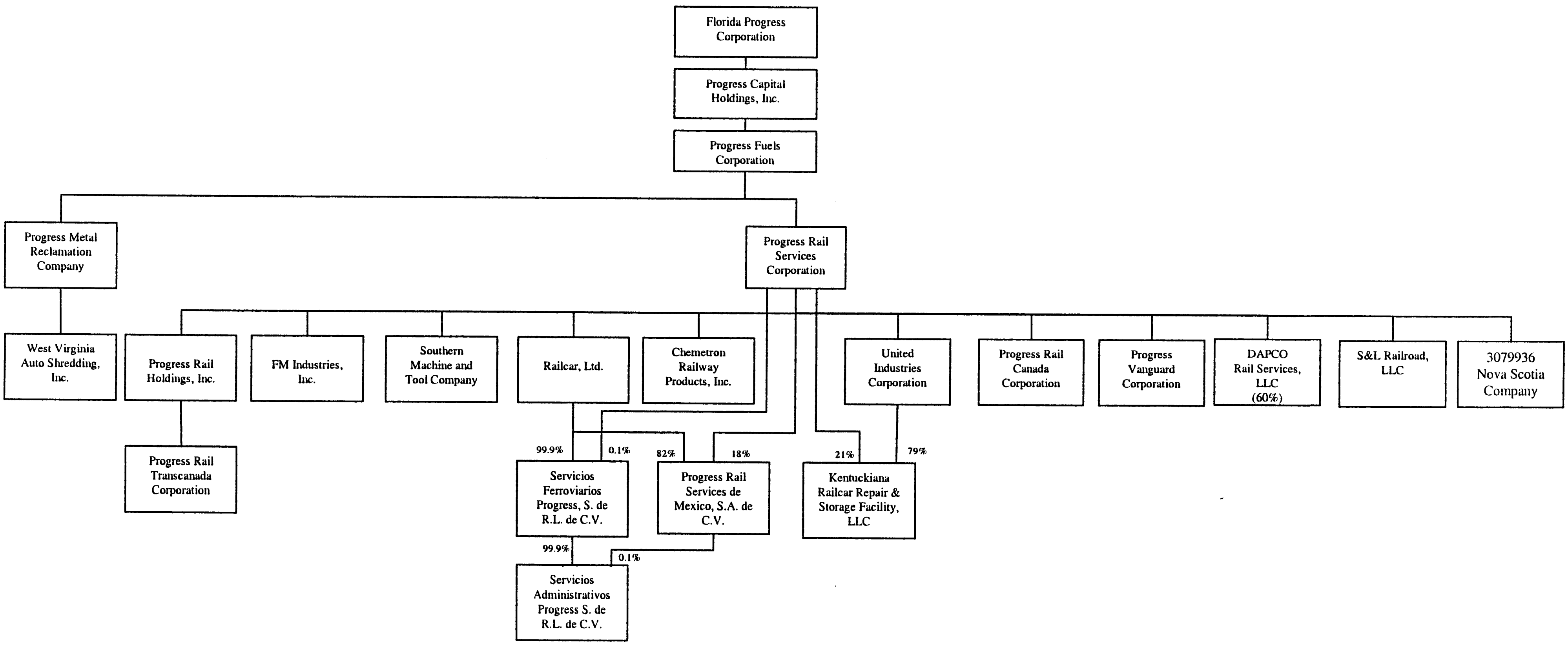
Progress Fuels Corporation

Gas Operations Group



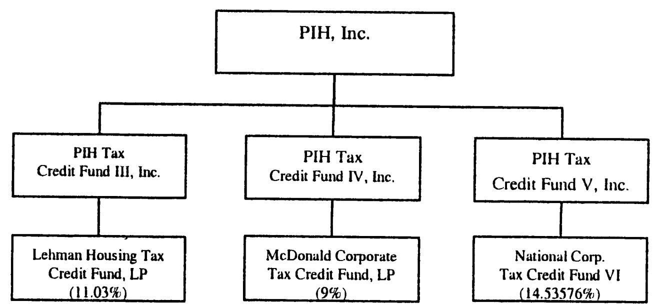
12-31-04

Progress Fuels Corporation
Rail Services Group



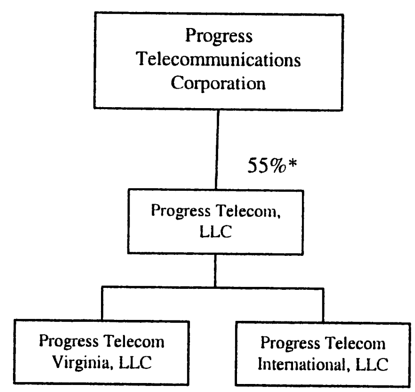
12-31-04

PIH, Inc.



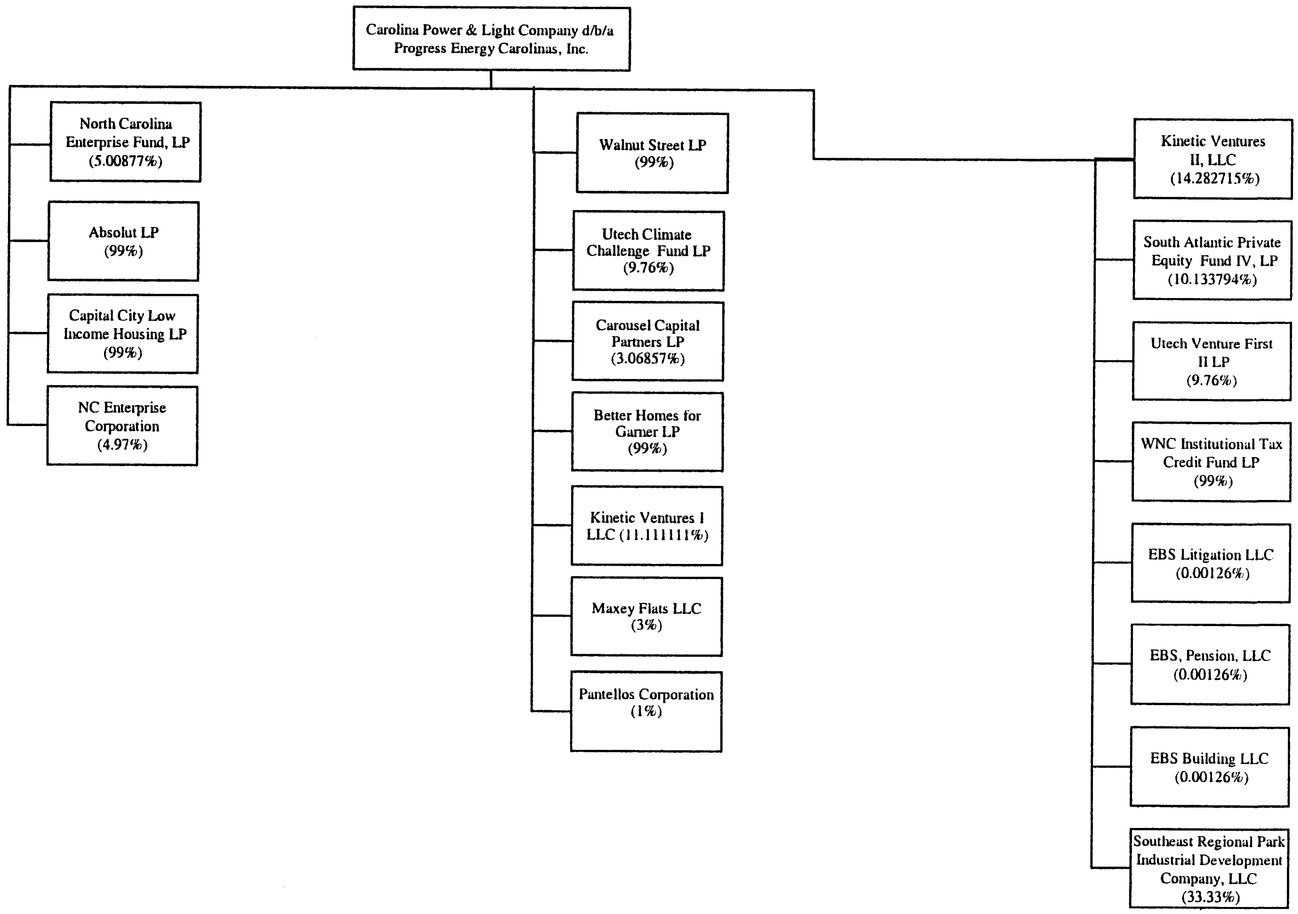
12-31-04

Telecommunications Group



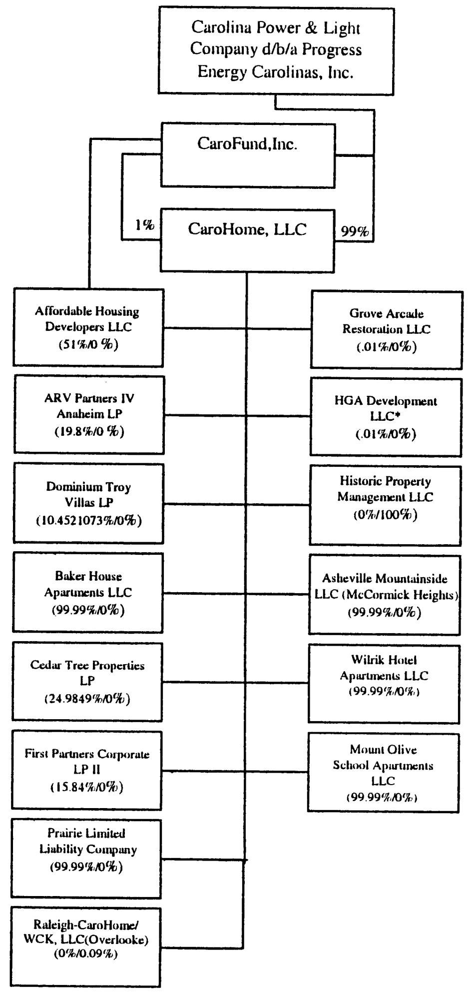
* Remaining 45% interest is owned by EPIK Communications, Inc., an unrelated third party

Progress Energy Carolinas (CP&L)
Other Investments



12-31-04

CaroHome / CaroFund Investments



Note: CaroHome % listed first, then CaroFund %

*: Also owned 0.01% by Historic Property Management LLC

12-31-04

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2004

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 the minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
	None

Analysis of Diversification Activity
Individual Affiliated Transactions in Excess of $500,000

Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2004

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 LLC	Employee benefits, Legal, IT, Acctg Svcs, Telecom, HR, Corp Comm, Risk Mgmt, Environmental Svcs, Corp Mgmt, Shared Corporate Svcs	$ 232,473,152
Progress Fuels Corporation	Coal purchases for Crystal River, hurricane support	335,118,934
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Gas purchases, Mgmt & IT services, Fuel procurement, Mgmt services, Customer Service support	55,700,052

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2004

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 liste 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)
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Load Generation support, Transmission/distribution support, Common Nuclear Svcs, Tech Svcs support, Core Environmental Svcs, CT Ops/Maint, Outside Support Svcs		S	1460001	16,374,027
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Inventory		S	2320601	757
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Gas purchases, Mgmt & IT services, Fuel procurement, Mgmt services, Customer Service support		P	2340001	52,435,955
Carolina Power & Light (d/b/a Progress Energy Carolinas)	Gas purchases		P	2320601	3,264,097
Progress Energy Ventures	Tech Svcs support, Core Environmental Svcs, CT Ops/ Maint		S	1460020	582,876
Progress Energy Ventures	Outside Support Services		S	1433110	67,461
Rowan County Power, LLC	Outside Support Services		S	1460024	27,026
Effingham County Power, LLC	Outside Support Services		S	1460025	48,645
DeSoto County Generating Company LLC	Outside Support Services		S	1460026	32,784
MPC Generating, LLC	Outside Support Services		S	1460032	14,067
Walton County Power, LLC	Outside Support Services		S	1460033	8,592
Washington County Power, LLC	Outside Support Services		S	1460034	4,490
Progress Fuels Corporation	Equipment, Outside Support Services		S	1460061	30,210
Progress Fuels Corporation	Coal, Outside Services		P	2340061	335,118,934

Analysis of Diversification Activity

Summary of Affiliated Transfers and Cost Allocations

Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2004

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 Fuels Corporation	Storm Support, Outside services		P	2320601	247,258
Progress Telecom Corporation	Revenue sharing		S	1460062	3,893,092
Progress Telecom Corporation	Fixed Assets		S	2340062	8,804,761
Florida Progress Corporation			S	1460SLM	2,332
Progress Telecom LLC	Network Services, IRU, Outside Services	12/19/2003	S	1460067	3,490,579
Progress Telecom LLC	Network Services	12/19/2003	S	1460062	1,162,964
Progress Telecom LLC	Network Services	12/19/2003	S	1433120	635
Progress Telecom LLC	Network Services	12/19/2003	S	1460162	1,127
Progress Telecom LLC	Inventory, Network Services	12/19/2003	P	2320601	56,586
Progress Telecom LLC	Network Services	12/19/2003	P	2340067	47,820
Strategic Resource Solutions Corp	Outside Services		P	2340085	74,000
Progress Energy Service Company LLC	Labor, Materials		S	1460098	11,493,477
Progress Energy Service Company LLC	Employee benefits, Legal, IT, Acctg Svcs, Telecom, HR, Corp Comm, Risk Mgmt, Environmental Svcs, Corp Mgmt, Shared corporate svcs		P	2340098	232,473,152
Progress Materials	Sale of Fly Ash, Potable/Process Water		S	1433055	702,835

Analysis of Diversification Activity
Assets or Rights Purchased from or Sold to Affiliates

Company: ***Progress Energy Florida Inc.***

For the Year Ended December 31, 2004

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 Energy Service Company	Radio System	$ 2,560,404	-	$ 2,560,404	$ 2,560,404	$ 2,560,404	Yes
Total		**$ 2,560,404**	-	**$ 2,560,404**	**$ 2,560,404**	**$ 2,560,404**	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
Total						**$**	

Analysis of Diversification Activity
Employee Transfers

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2004

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
SVC	PEF	Sr IT Analyst	Sr Tech Suppt Anlyst-IT	Permanent
PEC	PEF	Mgr-Northern Trans Area	Dir-Transmission Construction	Permanent
PEF	PEC	Lead Engr Technical Supt Spec	Lead Engr Technical Supt Spec	Permanent
SVC	PEF	Admin Asst to Department Head	Admin Asst to Department Head	Permanent
PEF	SVC	Energy Efficiency Spec-EDG	Claims Investigator	Permanent
PTL	PEF	Sr Account Exec-PTC	Sr Account Exec-PTC	Permanent
PEF	PEC	Supv-Nuc Info Tech	Supv-Nuclear Info Tech Svcs	Permanent
PEF	PEC	Plt Mgr-Bartow	Dir-Environmental Svcs-POG	Permanent
PEC	PEF	Engr	Engr	Permanent
SVC	PEF	Sr Auditor	Sr Bus Fin Anlyst	Permanent
PEF	PEC	Comb Turbine Technician	Comb Turbine Technician	Permanent
PEF	SVC	VP- So Central Region	VP-Corporate Services	Permanent
PEC	PEF	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
PEC	PEF	Mgr-Perf Eval & Reg Affairs	Mgr-Operations-NGG-CRP	Permanent
PEF	PEC	Mgr-Operations-NGG-CRP	Mgr-Maint-Nuc	Permanent
PEF	SVC	Sr Bus Fin Anlyst	Sr Bus Fin Anlyst	Permanent
PEF	PFC	Princ Tech Proj Mgmt Spec-POG	Princ Tech Proj Mgmt Spec-POG	Permanent
PEF	SVC	Admin Asst to Department Head	Data Management Asst I-FL	Permanent
PVI	PEF	Sr Comb Turbine Tech	Sr Comb Turbine Tech	Permanent
SVC	PEF	Sr Occ Health & Safety Spec	Sr Occ Health & Safety Spec	Permanent
PEC	PEF	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
PEC	PEF	Assessor-RNAS	Assessor-RNAS	Permanent
PEF	SVC	Lead Craft/Technical Trainer	Lead Craft/Technical Trainer	Permanent
PEC	PEF	Mgr-Call Services-ED	Dir-FL Cust Svc-ED	Permanent
PEF	PEC	Lead Engr	Lead Engr	Permanent
PEF	SVC	Sr Bus Fin Anlyst	Lead Bus Fin Anlyst	Permanent
PTL	PEF	Sr Corp Counsel & Mgr-Reg Aff	Mgr-System Engineering-DO&S	Permanent
PEC	PEF	VP-Western Region	VP-So Coastal Region	Permanent
PEC	PEF	Sr Access Authorization Spec	Supv-Access Authorization-CR	Permanent
PEC	PEF	Mgr-Dist Data & Design Svcs	Mgr-Tech Systems Support (INT)	Permanent
PEF	PEC	Production Specialist-POG	Mgr-Plt Production-CT(INT)	Permanent
PEC	PEF	Mgr-Plt Production-CT(INT)	Production Specialist-POG	Permanent
PEF	PEC	Bus Fin Anlyst	Bus Fin Anlyst	Permanent
PEF	PEC	VP-Dist Ops & Support	VP-Western Region	Permanent
PEC	PEF	Lead Engr	Sr Tech Proj Mgmt Spec-POG	Permanent
PEF	SVC	Lead Proj Spec-Matls-CORP SVS	Lead Proj Spec-Matls-CORP SVS	Permanent
SVC	PEF	Sr Auditor	Sr Engr	Permanent
SVC	PEF	Administrative Assistant I-FL	Administrative Assistant I-FL	Permanent
PEC	PEF	Sr Engr Technical Supt Spec	Sr Engr Technical Supt Spec	Permanent
SVC	PEF	FMS Fuels Analyst-PV	FMS Fuels Analyst-PV	Permanent
PEF	PEC	Supv-Configuration Management	Assessor-RNAS	Permanent
PEC	PEF	Lineman 3/C	Lineman 3/C	Permanent

Analysis of Diversification Activity
Non-Tariffed Services and Products Provided by the Utility

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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	4170000	Non-Regulated
Homewire	4170000	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: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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)	3,984,892	785,550	4,770,442
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other	234,775		234,775
Communication Equipment	-	9,272,430	9,272,430
Totals	$ 9,196,513	$ 10,057,980	$ 19,254,493

Number of Electric Department Employees

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

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)	**10/31/2004**
2. Total Regular Full-Time Employees	**4033**
3. Total Part-Time and Temporary Employees	**188**
4. Total Employees	**4221**

Details

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2004

Report the information specified below, in the order given, for the respective income deduction and interest charges account. Provide a subheading for each account and a total for each account. Additional columns may be added if deemed appropriate with

(a) Miscellaneous Amortization (Account 425): Describe the naure of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

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 then 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 Debit / (Credit)
Account 426 - Miscellaneous Income Deductions	
Civic & Community Organizations	$479,692.83
Education Related Contributions	$370,370.32
Health & Human Services Contributions	$72,734.14
Miscellaneous Cultural Organizations	$236,353.47
Other	$314,968.73
Progress Energy Foundations	2,750,000.00
Subtotal Accounts 4261014, 426180T, 4261BUD	$4,224,119.49
Investment in Company Owned Life Insurance	(1,462,738.24)
Subtotal Accounts 4262016, 4262041	(1,462,738.24)
Penalties	97,191.00
Subtotal Account 4263001	97,191.00
Certain Civic, Political & Related Activities	4,221,840.78
Subtotal Accounts 4264100, 4264200, 4264300	4,221,840.78
Other Deductions	781,009.91
Subtotal Account 4265001	781,009.91
Total Miscellaneous Income Deductions - Account 426	7,861,422.94
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	674,347.90
Other Interest Expense (4310001, 4310011)	246,065.19
Customer Deposits - Rate 6 to 7% per annum	7,732,452.59
Interest related to Projected Tax Deficiency on various audit issues - Rate 6.5%	(3,488,435.00)
Total Account 431	5,164,430.68